# CLASS VI PERMIT
# AREA OF REVIEW AND CORRECTIVE ACTION PLAN

**40 CFR 146.84(b)**

LOUISIANA GREEN FUELS
PORT OF COLUMBIA FACILITY

Prepared By:
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Revision No. 0
January 2023

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## 1.0 FACILITY INFORMATION

**Facility Name:** Louisiana Green Fuels, Port of Columbia Facility
Three Class VI Injection Wells

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**Well Locations:** Port of Columbia,
Caldwell Parish, Louisiana

**Name: Latitude / Longitude**
Well 1 (W-N1): 32.18812141510 / -92.10986101060
Well 2 (W-N2): 32.18686691570 / -92.05915551900
Well 3 (W-S2): 32.1639375970 / -92.08754320370

# 2.0 COMPUTATIONAL MODEL APPROACH

The models employed in this application meet specified requirements under 40 CFR §146.84 Area of Review and Corrective Action and under California Air Resources Board (CARB) LCFS Protocol Section C.2.4.1 and C2.4.2. The computational modeling predicts the projected lateral and vertical movement of the carbon dioxide plume and formation fluids in the subsurface, starting from the commencement of injection activities until:

- the plume movement ceases;
- pressure differentials sufficient to cause the movement of injected fluids or formation fluids upward into a USDW are no longer present; or
- until the end of a fixed time period (100 years PISC).

The models:

- are based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;
- take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and
- consider potential movement through faults, fractures, and artificial penetrations.

Owners or operators of Class VI wells must perform corrective action on all wells in the Area of Review that are determined to need corrective action, using methods designed to prevent the upward movement of fluid into or between underground sources of drinking waters (USDWs), including use of materials compatible with the carbon dioxide stream, where appropriate.

Louisiana Green Fuels will revisit the determination of the Area of Review at least every five years or when monitoring and operational conditions of the sequestration project warrant. Louisiana Green Fuels will:

(1) Reevaluate the Area of Review in the same manner as specified in this section, including any expansion in the size of the area;
(2) Identify all wells in the reevaluated Area of Review that require corrective action in the same manner specified in this section;
(3) Perform corrective action on any wells requiring corrective action in the reevaluated Area of Review in the same manner as specified in this section; and
(4) Submit an amended Area of Review and Corrective Action Plan or demonstrate through monitoring data and modeling results that no amendment to the Area of Review and Corrective Action Plan is needed.

The modeling in this report is intended to present a most likely prediction for the pressure build-up and plume extent over the injection and post injection life of the project. Site-specific data used in the model is derived from the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) and from relevant local and regional data representative for the injection site. These data are used as a basis for predicting the critical pressure and plume extent due to the injection / sequestration of carbon dioxide. Static and dynamic reservoir models are constructed to establish the most likely field development plan and expected plume extents with time. This model represents “most likely” scenario for computational modeling and will be updated to a final simulation following acquisition of additional data from the project injection wells and monitoring wells.

There are various physical and chemical processes that determine the efficiency and viability of carbon dioxide sequestration. Table 1 contains some of the modeled considerations. This application considers the effects of structural / stratigraphic trapping, capillary trapping, residual gas trapping and carbon dioxide solubility dissolution in *in-situ* trapping. Mineralogical trapping becomes more important at longer time scales (exceeding the Post Injection Site Closure, PISC, 100-year observation period) and is not modeled. Anticipated mineral trapping is discussed in **Module A**.

The project static model is constructed using Schlumberger’s Petrel software through the DELFI platform. The static model is used to define the geological model, including the two targeted Injection Zones (Annona Sand and the Upper Tuscaloosa / Paluxy). The Upper Tuscaloosa / Paluxy Injection Zone is the primary sequestration interval. The shallower Annona Sand Injection

Zone is expected to provide additional capacity, if needed later, but is being held in reserve. The dynamics of the injection process was then modeled using Petroleum Experts (PETEX) reservoir simulator, Reveal. Reveal provides a dynamic simulation of the pressure and plume movement in each of the targeted injection zones (Appendix 1). Assumptions and inputs in the models have been validated for site-specific conditions using local data obtained from Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). Figure 1 is a location map of the modeled area showing the location of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) and all other wells utilized in the modeling process. Transmissibility test data from the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) was used to "tune" the model, using brine as an analogous injection fluid.

**Table 1 Model Considerations**

| Process | Modeled |
|---|---|
| Structural trapping (note: no structural closures in the AoR) | No |
| Stratigraphic trapping (Primary Confining Unit) | Yes |
| Hydrodynamic trapping | No |
| Residual gas trapping | No |
| Geochemical trapping | No |
| Imbibition trapping | No |
| Capillary trapping and imbibition | Yes |
| CO2 solubility trapping with the *in-situ* formation water | No |
| Mineralogical transformation (trapping) | No |

Results from the computational models were used to establish the outer perimeter of the Area of Review. The Area of Review is defined as the area surrounding the sequestration project where the underground source of drinking water (USDW) could be endangered by injection operations. For the Louisiana Green Fuels Port of Columbia Facility, the Area of Review is further defined as the area that encompasses the critical pressure front (cone of influence) advancing ahead of the (modeled) maximum lateral (aerial) extent of the carbon dioxide plume. The area encompassed by the critical pressure front cone of influence is much larger than the aerial extent of the sequestered carbon dioxide plume; as such, its outer perimeter defines the Area of Review.

The following sections highlight each Model and its impact upon the development of the Area of Review and Corrective Action Plan for the Louisiana Green Fuels site at the Port of Columbia, Louisiana.

## 2.1 MODEL BACKGROUND

### 2.1.1 Site Geology

The demonstration of security for injection includes a geologic containment demonstration, *i.e.*, an absence of vertically transmissive faults in the path of the carbon dioxide plume that, if present, could act as conduits for carbon dioxide to leave the containment system.

The Injection Zone is defined as "the geologic formation, group of formations, or part of a formation that is of sufficient aerial extent, thickness, porosity, and permeability to receive the injected carbon dioxide through a well or wells associated with a geologic sequestration project". Injection targets are identified as formations encountered below a depth of 3,000 feet, which defines the general top of the "window" for supercritical carbon dioxide sequestration. Sequestration reservoir intervals, grouped within two injection zones, have been identified (shown on Figure 2 – Type Log), from the shallowest to the deepest formation, they are as follows:

- Upper Cretaceous Annona Sand; and
- Multiple sandstones of the Upper Cretaceous Upper Tuscaloosa Formation and the Lower Cretaceous Paluxy Formation.

The sandstones within both geologic intervals exhibit the necessary characteristics to be effective sequestration reservoirs at the Louisiana Green Fuels Port of Columbia Facility and are located more than 3,000 feet deeper than the lowermost aquifer that meets the criteria for being a USDW (less than 10,000 mg/l total dissolved solids content). This fresh-water bearing interval is identified as contained within basal sandstones within the Eocene-aged Sparta Formation. It should be noted that, within the Area of Review, the Sparta sandstones are not currently used as a source of drinking water.

#### *2.1.1.1 Annona Sand – Injection Zone 1*

The Annona Sand is a regionally extensive, bi-lobed glauconitic sandstone completely encased within impermeable Upper Cretaceous chalk strata between 4,144 feet and 4,182 feet in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). Figure 2 is the open hole geophysical well log from the Louisiana Green Fuels well, highlighting the Annona Injection Zone.

#### *2.1.1.2 Upper Tuscaloosa and Paluxy – Injection Zone 2*

Multiple sandstones of the Upper Cretaceous-aged Upper Tuscaloosa Formation (between the measured log depths of 4,911 feet and 5,630 feet) and the Lower Cretaceous-aged Paluxy Formation (between the measured log depths of 5,771 feet and 5,846 feet) in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) have been identified as potential injection intervals (Figure 2). With regard to the Paluxy Formation, additional potential sequestration reservoirs (stratigraphically deeper, porous and permeable, siliciclastic channel sandstones) have been identified in adjacent, deeper oil and gas test wells drilled within the Area of Review; these deeper channels sands will also be targeted by the proposed injection wells, which are proposed to be drilled to a total depth of 7,000 feet. The total depth of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) was 6,200 feet; accordingly, the proposed injection wells will penetrate an additional 800 feet, more or less, of Lower Cretaceous strata, within which several additional Paluxy sandstones (potential sequestration reservoirs) are likely to be encountered.

### 2.1.2 Static Model – Petrel

Schlumberger's Petrel software was used to generate a static geocellular model, which was then used as the basis for the Reveal dynamic simulation. Petrel was developed in Norway in 1989 by Technoguide and later acquired by Schlumberger in 2002. This software is designed to provide a full suite of reservoir characterization tools that enables the development of stratigraphic and structural reservoir understanding, moving seamlessly from two-dimensional (2-D) data to three dimensional (3-D) models. The relational workflow provides accuracy throughout the lifecycle.

Petrel is selected for this project because of its easy-to-follow workflow design and because it is one of the industry leaders for static geocellular modeling. It has been designed and used worldwide for reservoir evaluation and development projects.

Model construction begins with the definition of the model objectives. For the Louisiana Green Fuels site, the model objectives were to:

- Generate a 3-D realization of the subsurface within a defined area that incorporates each injection zone and the corresponding overlying impermeable rock layer.
- Populate the model with key rock properties using the existing dataset and stochastic distribution. For this project, the dataset allowed for the calculation of porosity, permeability, and an estimation of the expected net sand with tuning from the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841).
- Build a model that forms the basis for dynamic simulation using Reveal to predict the storage capacity of the selected subsurface intervals and to track the expected movement of the carbon dioxide plume and pressure variation (increase) while remaining safely under the regulatory-specified maximum injection pressure limits.

The identification of available data represents a critical first step in model construction. This data set includes well logs, core data, fluid data, and other available data. For projects investigating the permanent storage of carbon dioxide in saline reservoirs (*i.e.*, not depleted hydrocarbon-bearing reservoirs), the availability of such data may be more limited because the data described above is more abundant in areas where extensive oil and gas development has taken place and, during the course of such development, there existed a clear financial incentive to gather such data.

Because it was purposely designed to collect such critically important data, most of the data used for the static and dynamic model simulation was obtained from the drilling, coring and testing of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) (Appendix 2). Additional data was utilized from available offset oil and gas test wells drilled within approximately seven miles of the Port of Columbia Facility (Figure 1). These wells were drilled in the 1940s to 1980s and the data from such test wells includes open hole logs of varying quality and format. Some of the wells have commercially-available digital LAS files (source used: TGS). Well logs in the study area are available online in bitmap format through public domains such as the Louisiana Department of Natural Resources' (LDNR) Strategic Online Natural Resources Information Systems (SONRIS) (www.sonris.com) and through physical LDNR files maintained in the

Monroe District Office (**Module A**). Commercial sources of digital and raster data include TGS and IHS. Table 2 presents the standard well data nomenclature and the associated type of log measurements available for the area.

**Table 2 Log Type Identification**

| Log Acronym | Log Type | Unit of Measurement | Log Measurement |
|---|---|---|---|
| RES | Resistivity | Ohm-meters | Derives a formation's resistivity as the inverse of its conductivity (see Conductivity, below). |
| DT | Acoustic / Sonic | Microseconds/ft | Measures compressional and shear wave transit times through a formation. |
| DEN | Bulk Density | g/cm3 | Measures bulk formation density (*i.e.* matrix density plus that of fluids occupying pore space) using gamma rays (GR) scattered from a GR source irradiating the borehole. The GR intensity is related to the mineralogy and pore space occupied by the fluids. |
| NEU | Neutron | P.U. | Measures porosity using the input of neutrons into the formation and measuring the reduction in energy due to the interaction with hydrogen. |
| COND | Conductivity | Mho-m | Measures a formation's electrical conductivity, the inverse of which is derived resistivity |
| DPHI | Density Porosity | P.U. | Calculates formation porosity from the bulk density curve using the difference between bulk density values and the known density of formation grains and pore fluids. Calculated porosities can also be used to determine bulk density in those instances where the bulk density curve was not displayed on the log. |

A tabulation of the digital and raster data used in making the Petrel static geocellular model is contained in Section 3.0.

The digital well log data set used in creating the static model contains 22 primary wells with spontaneous potential (SP) or gamma ray (GR) curves, and the digital well data from each of these 22 wells also includes either a density porosity (DPHI) curve, a sonic travel time (DT) curve, or both porosity log curves. All of the available well data within the Area of Review was used in the petrophysical evaluation and was used in the construction of the static geocellular models. Wells with digital spontaneous potential and resistivity curve data represent the primary well data set that was used for structural interpretation (see **Module A**). Those wells with density, neutron, or sonic porosity logs were used to derive the porosity of the intervals of interest (Figure 2). The well data workflow used in static model generation is described in Section 3.0 – Model Input and Sources.

### 2.1.3 Dynamic Model – Reveal

Petroleum Experts' Reveal software has been selected for use in this application given its specialized modeling capabilities. Reveal is used throughout the energy and environmental industries by thousands of users. The software is fully thermodynamic and includes compositional equations of state (EOS) modeling of the fluids. Reveal provides several "solvers" (IMPES, Fully Implicit) and handles a variety of gridding scenarios (Cartesian, Corner Point, Curve-Linear, Radial and Core). The software provides the ability to model advective, diffuse and dispersive flow. In addition, Reveal can incorporate the PHREEQC database to calculate ionic and chemical reaction processes. Geomechanical modeling of the "cap rock integrity" and/or hydraulic fracturing is also available in the software. Appendix 1 contains the User's Manual for the Reveal software.

Reveal is also a specialized compositional reservoir simulator that can use the Peng-Robinson EOS to simulate the important mechanisms (phase behavior predictions) of a supercritical carbon dioxide sequestration process, including:

- carbon dioxide property changes with pressure / temperature;
- relative permeability changes with carbon dioxide saturation;
- carbon dioxide sequestration via capillary trapping and aqueous phase dissolution; and
- reservoir energy impacts associated with rock compressibility and pressure dissipation via an aquifer boundary condition.

The Reveal software was selected for the Area of Review modeling and delineation for this project as it is an industry-standard tool that has been demonstrated to effectively model rock and fluid effects associated with such carbon dioxide sequestration processes.

The following static properties were generated using the Petrel static model and provided inputs to the Reveal model using a corner-point grid format, in which grid block corners/node X/Y/Z coordinates are defined:

- Reservoir geometry (size, shape, and thickness)
- Net to Gross Ratio
- Porosity
- Horizontal permeability
- Vertical to Horizontal permeability ratio

This application models the mass injection and advective flow of supercritical carbon dioxide into a fully brine-saturated reservoir using finite difference methods. The Reveal model incorporates the effect of buoyant forces (gravitational effects) created by the density contrast between the injected supercritical carbon dioxide and the *in-situ* formation brine. Temperature effects, resulting from the injection of cooler carbon dioxide into the reservoir, as well as depth-related *in-situ* temperature variations, were also considered in the model.

The supercritical carbon dioxide density was estimated using Reveal's implementation of the Peng-Robinson EOS[1]. The Reveal software solves the Peng-Robinson equation by integrating the pressure, temperature, and starting composition of a grid cell. It then calculates the composition of each of the two possible phases within which the fluid might exist, either a gaseous and/or an oleic (oil) phase for that cell. The mole density (number of moles per unit volume of the phase) is also calculated. The Lohrenz, Bray Clark[2] method is used to estimate carbon dioxide viscosity by calculating the gas viscosity based upon the composition of the gas.

Petroleum Experts provides an internal method to estimate the density and viscosity of aqueous phases. The Reveal software also provides an estimate of water density change created by the dissolution of the injected carbon dioxide. These methods are presented in Appendix 1.

Regarding the Finite Difference method, there are many publications that offer very detailed explanations of how this method is implemented. Documentation provided by Petroleum Experts that is specific to the Reveal software is included in Appendix 1.

The Finite Difference application models the mass injection and advective flow of supercritical

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[1] Robinson, D.B. and Peng, D.Y., 1976, A New Two-Constant Equation of State Industrial and Engineering Chemistry: Fundamentals. Industrial & Engineering Chemistry Fundamentals, 15, 59-64

[2] Lohrenz, J., Bray, B.G., Clark, C.R., 1964, Calculating Viscosities of Reservoir Fluids from their compositions: SPE Paper 915, Journal of Petroleum Technology, p. 1171-1176

carbon dioxide into fully brine- saturated reservoirs using a finite difference simulator. The model takes into account the effect of buoyant forces (gravitational effects) created by the density contrast between the carbon dioxide injectate and the *in-situ* water.

## 2.2 SITE GEOLOGY AND HYDROGEOLOGY

The demonstration of security for injection includes a geologic containment demonstration and the documentation of the absence of vertically transmissive faults that could form breaches of the containment system (**Module A**). The Louisiana Green Fuels Port of Columbia Facility is located in an area of Northern Louisiana typified by an absence of significant geological structural impacts (*i.e.* an absence of faults, uplifts, domes, etc.). The multiple sandstone reservoirs of the Upper Tuscaloosa / Paluxy Formations comprise a series of stacked, alternating sandstones and interlayered shale beds. The younger Upper Cretaceous Annona Sand represents a widely-distributed "blanket sand" within the Area of Review. The layering of the Cretaceous strata within the in Area of Review is textbook "layer cake", in the sense that the strata exhibit only minor monoclinal structural dip and a gradual thickening of each stratigraphic unit in a south-southwest (paleo-coastal) direction. The layer cake distribution of the Cretaceous strata is impacted by unconformities that are observed to be present within and atop the Upper Cretaceous stratigraphic section; such unconformities are the result episodic regional upwarping associated with the Monroe Uplift in the area north of the Area of Review. For example, the up dip limit of the Upper Tuscaloosa is characterized by the truncation of the interval to the north of Caldwell Parish, in the Ouachita and Richland Parishes area. This truncation, the result of two significant unconformities, occurs approximately 10 miles north of the projected northern perimeter of the Area of Review (the most significant being the truncation of all Cretaceous strata by the Paleocene Midway Shale).

The immediate top seal for the Upper Tuscaloosa consists of the impermeable shales, marls and calcareous beds (chalks, limestones and calcareous mudstones) of the overlying Upper Cretaceous Selma – Austin Chalk stratigraphic interval. This containment interval includes the especially thick stratigraphic interval that extends from the base of the (basal Selma) Annona Sand to the base of the Austin Chalk equivalent, which in turn directly overlies the Upper Tuscaloosa Formation. Additionally, the thick impermeable marls and shales of the 600-foot-thick Paleocene Midway Shale form a very effective regional top seal for the entire Tuscaloosa interval, as well as all other Mesozoic strata. The Midway Shale is designated as the Upper Confining Zone for the proposed sequestration project. The effectiveness of this thick and impermeable top seal has been demonstrated, for example, by the entrapment of giant accumulations of oil and gas beneath the Midway Shale at Delhi and Monroe Fields in the Morehouse, Ouachita and Richland Parish areas.

The two injection zones that have been modeled are:

- The bi-lobed, locally "blanket" sandstone of the Upper Cretaceous Annona Sand
- The multiple sandstones of the Upper Cretaceous Upper Tuscaloosa / Lower Cretaceous Paluxy Formations

There are four confining / containment zones known to exist between the lowermost USDW (base Sparta) and the top of the Upper Tuscaloosa Formation. These are (from shallowest to deepest):

- The Eocene Cane River Formation, the aquitard immediately beneath the USDW
- The ~600-foot-thick shales of the Midway Shale (the Paleocene Midway Group)
- The ~300-foot-thick impermeable chalks of the Upper Cretaceous Selma Chalk
- The ~700-foot-thick argillaceous, ductile mudstones of the Middle and Lower Chalk

These intervals are identified on the Type Log presented in Figure 2, which uses the open hole log from the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) well.

Figure 3 presents the locations of the proposed sequestration injection wells, project monitoring wells, and the locations of nearby legacy (pre-existing oil and gas test) wells. Wells used for detailed correlation within the confines of the static model are shown in Table 3.

The Primary Injection Zone is the multiple sandstones of the Upper Cretaceous Upper Tuscaloosa / Lower Cretaceous Paluxy Formations, which are overlain by the Austin Chalk (upper containment interval) and underlain by the Mooringsport / Ferry Lake Formations (the latter of which comprises the Lower Confining Zone). The Annona Injection Zone, which is fully encased within the Upper Cretaceous Chalk, is held in reserve; however, it was included in the modeling.

**Table 3 Wells used for generating major structural surfaces in the static model**

| Well identifier | API | Lithology Logs | Porosity Logs |
|---|---|---|---|
| Alma F. Jones #1 | 170212012700 | Spontaneous Potential, Induction | |
| Benny White #1 | 170732057600 | Gamma Ray, Spontaneous Potential, Resistivity | Density |
| C. O. Howard #1 | 170212075500 | Gamma Ray, Spontaneous Potential, Resistivity | Density & Sonic |
| Chas. G. Simmons #1 | 170210002300 | Spontaneous Potential, Induction | |
| Devon-Donner 11-1 #1 | 170732240100 | Spontaneous Potential, Induction | |
| Devon-Donner 6 #1 | 170212143700 | Gamma Ray, Spontaneous Potential, Resistivity, Photo Electric | Density |
| Ewing C #2 | 170732223700 | Gamma Ray, Spontaneous Potential, Resistivity | Sonic |
| HOSS RA SUE: L. C. Ewing et al #001-ALT | 170212112300 | Gamma Ray, Spontaneous Potential, Resistivity | Density |
| HOSS RA SUH; Santa Fe Snyder #23 | 170212139800 | Gamma Ray, Spontaneous Potential, Resistivity, Photo Electric | Density |
| HOSS RA SUN; KMI Land #1 | 171272168600 | Spontaneous Potential, Induction | |
| HOSS RA SUT; Manville 9-15 #1 | 170212117600 | Gamma Ray, Spontaneous Potential, Resistivity | Density |
| J. F. Magalie-Kellogg Bros. Inc, #1 | 170210007200 | Spontaneous Potential, Induction | |
| Keahey, J., Jr. #1 | 170212060900 | Gamma Ray, Spontaneous Potential, Resistivity, Photo Electric | Density |
| LA Central Lumber Co. Tr. #E-1 | 170210007500 | Spontaneous Potential, Induction | |
| La Salle Land Co. #C-1 | 170210011100 | Spontaneous Potential, Induction | |
| Louisiana Green Fuels #1 | 170218801800 | Gamma Ray, Spontaneous Potential, Resistivity, Photo Electric | Density & Sonic |
| Manville 32-13 #1 | 170212111300 | Gamma Ray, Spontaneous Potential, Resistivity, Photo Electric | Density & Sonic |
| Manville Forest Products 32-10 #1 | 170212117800 | Spontaneous Potential, Induction | |
| Manville Forest Products Co. #1 | 170212089700 | Gamma Ray, Spontaneous Potential, Resistivity, Photo Electric | Density & Sonic |
| Meredith #1 | 170210007100 | Spontaneous Potential, Induction | |
| Pine Pipeline, Inc. 7-9 #1 | 170212108800 | Gamma Ray, Spontaneous Potential, Resistivity, Photo Electric | Density & Sonic |
| Shipp #1 | 170212013100 | Spontaneous Potential, Induction | |
| Terran #1 | 170732116900 | Gamma Ray, Spontaneous Potential, Resistivity | Density |

## 2.3 MODEL DOMAIN

In order to capture the advancing plume and pressure front through dynamic modeling, the model boundary was selected to encompass a wide enough area such that neither the plume nor the pressure front would reach the edge of the model over the course of the modeled injection and post injection time period. Figure 4 shows the model boundary and coordinates of the model corners.

The corner point grid created in Petrel was exported in the "Eclipse ASCII format" and imported into the Reveal dynamic simulation software. The static model covers an area of 118,000 by 75,500 ft (22.3 x 14.2 miles), or approximately ~320 square miles. The model consists of 236 cells in the X direction, 151 cells in the Y direction, and 51 total layers in the Z direction. Each cell block has uniform X-Y dimensions of 500 x 500 feet, respectively. Cell block height varied depending on the distance between the upper and lower confining zones for each injection zone.

The static grid was further refined in Reveal to yield three separate Reveal dynamic models.

- Annona Injection Zone: 3 layers
- Upper Tuscaloosa/Paluxy Injection Zone
    - Upper Tuscaloosa (Upper Interval): 29 layers
    - Upper Tuscaloosa (Lower Interval) / Paluxy: 19 layers

Figure 5 shows the skeleton grid in three dimensions and the model domain information is summarized in Table 4.

**Table 4 Model domain information**

| | | | |
|---|---|---|---|
| **Coordinate System** | SPCS27_1701: NAD27 Louisiana State Planes, Northern Zone, US Foot | | |
| **Vertical Datum** | Mean Sea Level (MSL) | | |
| **Coordinate System Units** | Feet-US | | |
| **Zone** | SPCS Louisiana North | | |
| **FIPSZONE** | 1701 | **ADSZONE** | 4026 |
| **Coordinate of X min** | 2,050,650 | **Coordinate of X max** | 2,168,650 |
| **Coordinate of Y min** | 505,800 | **Coordinate of Y max** | 581,300 |
| **Minimum Depth (Z)-TVDSS** | 3,329 | **Maximum Depth (Z)-TVDSS** | 7,015 |

This excerpt, from the Reveal Users guide (Appendix 1), describes the implementation of the corner point grid within the software.

> "*Corner point (full) - in this scheme each block has 8 independent coordinates, giving (2*NX) * (2*NY) * (2*NZ) coordinates in total. These are entered as X, Y and Z coordinates for each layer, with (2*NX) * (2*NY) entries per layer for each spatial direction. Each block is considered in turn and its two corner point coordinates are entered before the next block data is entered.*"

The origin (cell block 1,1,1) in Reveal represents the upper left (northwest) corner of the grid. Layer 1 represents the shallowest layer; layer depth increases with each subsequent layer number. Layer dimensions are measured in feet and vertical distance is measured in True Vertical Depth (TVD) relative to sea level (TVD-SS).

The origin (cell block 1,1,1) corresponds to geospatial coordinates of 2,050,650 easting, 581,300 northing using NAD27 North Louisiana State Plane coordinates. The grid extends 118,000 feet (22.3 mi) horizontally and 75,500 feet (14.3 mi) vertically. The geospatial coordinates of the lower right (southeast) corner of the grid (cell block 236,151,1) are 2,168,650 easting and 505,800 northing (Figure 5).

### 2.3.1 Model Layering

The construction of the Static Model begins with the generation of the model framework. For the area surrounding the Louisiana Green Fuels Port of Columbia Facility, no faults have been identified in the well logs, on available 2-D seismic data (**Module A**), or on commercially available structure maps produced by unrelated third parties. This lack of faulting makes the Static Model less complex and more reflective of an infinite acting reservoir. Key well data has been imported into Petrel and the key stratigraphic intervals were converted to structural surfaces in Petrel using correlated well tops as the foundation for such surfaces.

Model construction began with the correlation of 11 key regional stratigraphic horizons, starting at the top of the Eocene Cane River Formation (approximate USDW) and proceeding deeper through the stratigraphic column to the Lower Cretaceous Ferry Lake Massive Anhydrite. Figure 2 is a stratigraphic column for the entire section encountered in the modeled area. In order to reduce model run times, only the interval from the top of the Annona Sand (Figure 6) through the Upper Tuscaloosa (Figure 7) to the base of the Paluxy P-3 Sand (Figure 8) was modeled. Correlations of the sub-intervals within the Upper Tuscaloosa (Figure 7) are discussed in the following sections.

The remaining key stratigraphic intervals (Top to Base Annona Sand; Upper Tuscaloosa; Middle Tuscaloosa Shale; and Top to Base Paluxy (P-3 Sand); Figure 9) were converted to structural surfaces in Petrel using the "Make Surface" function, utilizing only the well tops as input data. These major structural surfaces were then trimmed to the size of the model area (Figure 4). Each of the modeled, structured surfaces (known as "Horizons" in Petrel) are shown diagrammatically in Appendix 3. These surfaces were then utilized as inputs to the model construction workflow, utilizing the "Make Simple" grid function in Petrel.

**Annona Sand Interval**

The Annona Sand is correlated across the modeled area as shown in Figure 6. Its thickness varies from 44 feet to as much as 101.5 feet in the 11 wells within the modeled area. At the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841), the Annona Sand interval presents as two sandstone lobes separated by a shalier interval. To capture this, the Annona interval is subdivided into three proportional layers within the model. The conformable layering of the Annona is shown in the intersection windows presented in Figures 10 and 11.

**Upper Tuscaloosa Interval**

Due to the thickness of the Upper Tuscaloosa, further subdivision of the interval was required. Therefore, utilizing the wells in Table 5 (locations shown in Figure 1), the Upper Tuscaloosa was subdivided into the detailed correlation scheme illustrated in Figure 7. This resulted in the Upper Tuscaloosa interval being divided into twelve sublayers of alternating sandy and predominantly shaley packages. Sands within the Lower Tuscaloosa interval were not modeled for dynamic simulation due to information obtained from testing at the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). The lack of prospective injectivity in the Lower Tuscaloosa Basal Sand in the Area of Review, due to its higher clay content (which clogs pore throats and inhibits porosity and permeability), had been predicted prior to testing, and was confirmed. Each of these structural surfaces can be seen in Appendix 3.

**Table 5 Wells used for Detailed Correlations of the Tuscaloosa Formation**

| Well Name | API Number | Lithology Logs | Porosity Logs |
|---|---|---|---|
| Chas. G. Simmons #1 | 170210002300 | Spontaneous Potential | None |
| C. O. Howard #1 | 170212075500 | Gamma Ray, Spontaneous Potential | Density, Sonic |
| Devon-Donner 6 #1 | 170212143700 | Gamma Ray, Spontaneous Potential, Photoelectric Index | Density |
| HOSS RA SUE: L. C. Ewing et al #001-ALT | 170212112300 | Gamma Ray, Spontaneous Potential | Density |
| HOSS RA SUH; Santa Fe Snyder 23 #1 | 170212139800 | Gamma Ray, Spontaneous Potential, Photoelectric Index | Density |
| HOSS RA SUT; Manville 9-15 #1 | 170212117600 | Gamma Ray, Spontaneous Potential | Density |
| Keahey, J., Jr. #1 | 170212060900 | Gamma Ray, Spontaneous Potential | Density |
| Louisiana Green Fuels #1 | 170218801800 | Gamma Ray, Spontaneous Potential, Photoelectric Index | Density, Sonic, Nuclear Magnetic Resonance |
| Manville 32-13 #1 | 170212111300 | Gamma Ray, Spontaneous Potential, Photoelectric Index | Density, Sonic |
| Manville Forest Products Co. #1 | 170212089700 | Gamma Ray, Spontaneous Potential, Photoelectric Index | Density, Sonic |
| Meredith #1 | 170210007100 | Raster ILD/SP | None |
| Pine Pipeline Inc. 7-9 #1 | 170212108800 | Gamma Ray, Spontaneous Potential | None |

The twelve Upper Tuscaloosa layers are further subdivided through the “Make Layers” function in Petrel. This further subdivision of the Upper Tuscaloosa portion of the model into sublayers is illustrated in Figure 12. Ultimately, the Upper Tuscaloosa was subdivided into 42 conformable model layers by evenly subdividing each of the intervals proportionally between the top and the base of each horizon (Figure 12). The layers are summarized in Table 6. An intersection window of these additional layers can be seen in Figures 10 and 11.

**Table 6 Sublayers in the Upper Tuscaloosa Formation**

| Upper Tuscaloosa Horizon | Number of Conformable Layers |
|---|---|
| Tuscaloosa A | 10 |
| Tuscaloosa B | 1 |
| Tuscaloosa C | 5 |
| Tuscaloosa D | 1 |
| Tuscaloosa E | 5 |
| Tuscaloosa F | 1 |
| Tuscaloosa G | 5 |
| Tuscaloosa H | 5 |
| Tuscaloosa I | 1 |
| Tuscaloosa J | 5 |
| Tuscaloosa K | 1 |
| Tuscaloosa L | 2 |

**Paluxy Interval**

The Paluxy Formation within the Area of Review comprises a progradational unit associated with alternating fluvial and marginal marine depositional environments (Caughey, 1977, Mancini and Puckett, 2000). Because the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) bottomed in the Upper Paluxy at a total depth of 6,200 feet, only the top of the Paluxy Formation, the Paluxy P-1 Sand, P-2 Sand, and P-3 Sand (top and base) are included in the model. This subdivision yielded 4 separate layers within the Upper Paluxy (Figure 8). The Paluxy injection intervals (reservoirs) encountered in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) are interpreted to be dip-oriented lenticular channel sandstones, approximately one mile in average width, with maximum gross thicknesses in the 50 to 60 foot range; because of their stratigraphically-limited aerial extent and the few number of Paluxy penetrations, each such channel is interpreted to have been encountered in only a few (if any) of the legacy Paluxy penetrations located within the modeled area. The dimensions and dip-orientations of the targeted channels are based upon analogous Paluxy channels mapped using 3D seismic data in neighboring Franklin Parish, east of the project site. Due to the lack of Paluxy penetrations within the modeled area, the Paluxy P-2 and Paluxy P-3 Sands are modeled as a single channel facies (the Paluxy P-1 Sand was too thin). Facies maps for the Paluxy P-2 and P-3 Sands, and the input data utilized to map these channels, are presented in Appendix 4.

# 3.0 MODEL INPUT AND SOURCES

Prior to dynamic modeling, an understanding of the regional and local subsurface geology was essential to accurately constructing the Static Model and to assess potential injection formations. Based upon the interpretation and evaluation of cores, borehole geophysical logs, and published literature sources, a comprehensive picture of the subsurface geology has been developed from compiled geologic material. The primary source of site-specific geologic information is gathered from data generated during the drilling, coring, logging and testing of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841).

Input parameters required by the model fell within the following areas:

- layer thickness and variation,
- permeability of the formations,
- porosity of the formations,
- compressibility of the formations and formation fluids,
- formation fluid and carbon dioxide viscosity and density,
- original formation pressure,
- relative permeability characteristics,
- formation characteristics, and
- boundary condition

Multiple sets of data were used to evaluate and determine parameter inputs in the Static and Dynamic Models for the Louisiana Green Fuels Port of Columbia Facility. Where site-specific data was not available, conservative assumptions were made using literature sources. The spatial variability and distribution of data for the formations of interest will be resolved with the subsequent drilling of the proposed injection wells and the conversion of certain legacy wells to monitor wells, and this new data will be incorporated into future refinements to the site model.

Wells used in the petrophysical analysis input to the Static Model were available through public domain (SONRIS) and commercial (TGS, IHS, etc.) databases. A total of 22 area well logs (Table 7) were evaluated for use in the Static Model. The locations of these wells is shown in Figure 1.

**Table 7 Wells with Logs used to evaluate Petrophysical data for the Static Model**

| Well Name | API Number | Lithology Logs | Porosity Logs | Core Anal. |
|---|---|---|---|---|
| Amason, E. #1 | 170212030500 | Gamma Ray & Spontaneous Potential | Density & Sonic | |
| Benny White #1 | 170732057600 | Gamma Ray & Spontaneous Potential | Density | |
| Biedenhorn Realty Co. #1 | 170212025800 | Gamma Ray & Spontaneous Potential | Density | |
| Broyles Ewing et al #1 | 170212112300 | Gamma Ray & Spontaneous Potential | Density | |
| C. O. Howard #1 | 170212075500 | Gamma Ray & Spontaneous Potential | Density & Sonic | |
| Ewing #1 | 170732116900 | Gamma Ray & Spontaneous Potential | Density | |
| Ewing #1 | 170732242400 | Gamma Ray & Spontaneous Potential | Density | |
| Ewing, C. #1 | 170732223700 | Gamma Ray & Spontaneous Potential | Density & Sonic | |
| HOSS RC SUA; Blackstone Mineral LP #1 | 170212143000 | Gamma Ray & Spontaneous Potential | Density | |
| HOSS RC SUA; Blackstone Mineral LP #1 | 170212145400 | Gamma Ray & Spontaneous Potential | Density | |
| HOSS RC SUB; Devon-Donner 6 #1 | 170212143700 | Gamma Ray & Spontaneous Potential | Density | |
| HOSS RC SUH; Devon-Donner 31 #1 | 170212144700 | Gamma Ray & Spontaneous Potential | Density | |
| Keahey, J., Jr., #1 | 170212060900 | Gamma Ray & Spontaneous Potential | Density, NMR & Sonic | Yes |
| Louisiana Green Fuels #1 | 170218801800 | Gamma Ray & Spontaneous Potential | Density | Yes |
| Manville 32-13 #1 | 170212111300 | Gamma Ray & Spontaneous Potential | Density & Sonic | Yes |
| Manville 9-15 #1 | 170212117600 | Gamma Ray & Spontaneous Potential | Density & Sonic | |
| Manville Forest Products #1 | 170212089700 | Gamma Ray & Spontaneous Potential | Density & Sonic | |
| MH B SUC; Devon Donner #1 | 170212143200 | Gamma Ray & Spontaneous Potential | Density | |
| Pine Pipeline Inc. 7-9 #1 | 170212108800 | Gamma Ray & Spontaneous Potential | Density & Sonic | |
| Santa Fe Snyder 23#1 | 170212139800 | Gamma Ray & Spontaneous Potential | Density | |
| Snyder Oil Corp ET AL #1 | 170212136800 | Gamma Ray & Spontaneous Potential | Density & Sonic | |
| Soigner #1 | 170732092700 | Gamma Ray & Spontaneous Potential | Density & Sonic | |

## 3.1 POROSITY

Porosity is defined as the ratio of void space in a given volume of rock to the total bulk volume of rock and is expressed as a percentage (Amyx et al., 1960). The more porous a rock is, the more fluid can be present in a given rock volume at a given time. Total porosity is the ratio of pore volume to the total volume of the rock. Effective porosity is the ratio of interconnected pore volume to the total volume of rock.

A rock's porosity type is highly dependent on the mineral composition of the rock and defines how much pore volume is accessible to reservoir fluids, *i.e.*, the ratio of total to effective porosity. Primary intergranular porosity results from preservation of pore space after deposition and lithification of sediments. Microporosity, which is associated with clays and dissolution of framework grains, is frequently present within the rock matrix and potentially affects the volume of effective porosity accessible by reservoir fluids. The macroporosity space is the volume accessible to fluids while the microporosity space is often filled with clay bound (immovable) water as well as capillary-bound fluids. When modeling porosity, a decision must be made as to whether to model total porosity or effective porosity. Since there is a high level of uncertainty associated with calculating effective porosity from log data and in quantitatively measuring effective porosity from a limited number of cores, the decision was made to model total porosity.

The following sections detail the available data sets, the method used for determining the porosity for the injection zones, and the resulting numerical assignments used within the model.

### 3.1.1 Data Sets

The petrophysical evaluation was principally calibrated using the substantial data recently obtained from the drilling, coring and testing of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). Petrophysical data from legacy wells located within the surrounding area were also reviewed to evaluate general porosity trends across the stratigraphic column. Data sets included geophysical well logs, regional core data, and published literature sources. The Shreveport Petroleum Data Association (SPDA) provides a commercial database of core and petrophysical data. A search of the SPDA database yielded other model data input parameters (*i.e.*, grain density values, etc.) that were used for the petrophysical evaluation of the targeted injection zones.

Additional site-specific data will be collected during the drilling and testing of the proposed injection wells as well as the deepening and/or recompletion of the proposed monitor wells. Anticipated core analyses will include both routine (porosity, permeability, and grain density measurements) and advanced analyses (SEM, x-ray diffraction, geomechanical testing, relative permeability measurements, etc.). Details of the anticipated testing program are contained in the "*Pre-Operational Testing and Logging*" plan contained in **Module D**.

### 3.1.2 Methodology

Well logs were uploaded into Schlumberger's Techlog©, which is an integrative software program available from Schlumberger. This software program was developed to allow the user to evaluate and interpret well log data and integrate core data. The software allows comparison of the mathematical models with calibration data such as core, well tests, formation and fracture pressure measurements, among others. The results are then exported in a digital format compatible with the static and dynamic modeling packages.

Ideally, the Static Model would contain effective porosities as an estimate of representative volume accessible to fluids. However, as noted above, accurate effective porosity quantification is difficult to determine, requiring calibration obtained from Nuclear Magnetic Resonance (NMR) measurements. In the absence of NMR data, effective porosities could be estimated from shale volume content; however, a large degree of uncertainty exists with that method, given that clay type influences the calculation of clay-bound and capillary-bound volumes. Due to the limited number of sample measurements and the unavailibility of advanced logs, total porosity values are used in the Static Model. These total porosity values are discounted by using a saturation height function, derived from capillary pressure measurements.

Bulk density logs and sonic logs from some legacy wells and the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) located near the Port of Columbia Facility were analyzed (see Table 7). Porosity calculated from bulk density is considered the most representative petrophysical estimate of the property in a formation, followed by the sonic porosity estimate. However, sonic porosity estimates are affected by the grain framework, as well as the saturating fluids or gases (to a larger extent); and sonic logs cannot detect or measure microporosity. Porosity estimates from neutron logs are not considered individually representative as clay-bound water (and gas) introduces excess porosity due to its hydrogen response. The clay-bound water is part of the clay matrix structure, and although it appears as part of the total porosity, it is pore space that is inaccessible to fluids. Such inaccessible pore space is thus not part of the effective pore volume.

The first step in the petrophysical analysis is to identify the permeable strata within the target formations. After establishing the sequence of permeable layers, total porosity is calculated primarily using density log data, as it is the most reliable / representative method. Only a fraction of the legacy well database included density logs run across the targeted Cretaceous intervals, so sonic log data was used where density log data was unavailable to provide a more robust dataset. Porosity estimates from sonic logs were compared with their density log counterparts in wells where both measurements were available. This allows for development of correct input parameters for the petrophysical evaluation of a larger well data set than would otherwise be available.

Wells where density logs were available for porosity evaluation are listed in Table 8 and are identified on Figure 1. The assumption of a single lithology for total porosity estimates is suitable for the proposed injection zones and overlying and underlying containment zones. Porosity model parameters were determined from core grain density measurements obtained from the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). Based on the core data, an average grain density of 2.65 g/ g/cm$^3$ was used in the model. The fluid density in the invaded zone within permeable intervals was estimated to be 1.00 g/cm$^3$. This is reflective of the invasive mud filtrate from the fresh-water mud system commonly used to drill such legacy wells in the Area of Review.

The density porosity equation is shown below (Schlumberger (1989); Asquith and Krygowski (2004)):

$$\emptyset_{density} = \frac{\rho_{matrix} - \rho_{bulk}}{\rho_{matrix} - \rho_{fluid}}$$

Where:

$\emptyset_{density}$ = total porosity

$\rho_{matrix}$ = mean density of the matrix minerals

$\rho_{bulk}$ = bulk density

$\rho_{fluid}$ = density of the fluid

Porosity measurements are calculated using the Raymer-Hunt equation for sonic logs (Raymer et al., 1980). This method employs using reference matrix compressional slowness values for silica sand and a representative regional shale combination.

$$\emptyset_{sonic} = C\frac{\Delta t_{log} - \Delta t_{matrix}}{\Delta t_{log}}$$

Where:

$\emptyset_{sonic}$ = total porosity

$C$ = 0.625 (also represented as 5/8) constant factor

$\Delta t_{log}$ = sonic response at depth of interest

$\Delta t_{matrix}$ = response associated with matrix

Sonic log porosity analysis, derived from acoustic travel time, is dependent on estimating the formation pressures and the compressibility of the material. As these site-specific parameters were estimated, the total porosity values from the sonic logs were considered conservative.

Core analyses obtained in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) were used for the calibration of the porosity in the open hole log computations (**Module A**).

Additional site-specific core measurements will be incorporated into the models after the drilling and testing of the injection wells to improve the accuracy of model results.

### 3.1.3 Porosity Modeled

Within the modeled area, 9 wells had porosity logs that were used in distributing the porosity property (Figure 1). These 9 wells are identified in Table 8 below.

**Table 8 Wells used for Modeling Porosity Distribution in the Static Model**

| Well Name | API Number | Lithology Logs | Porosity Logs |
|---|---|---|---|
| C. O. Howard #1 | 170212075500 | Gamma Ray, Spontaneous Potential | Density, Sonic |
| Devon-Donner 6 #1 | 170212143700 | Gamma Ray, Spontaneous Potential, Photoelectric Index | Density |
| HOSS RA SUE: L C Ewing et al #001-ALT | 170212112300 | Gamma Ray, Spontaneous Potential | Density |
| HOSS RA SUH; Santa-Fe Snyder 23 #1 | 170212139800 | Gamma Ray, Spontaneous Potential, Photoelectric Index | Density |
| HOSS RA SUT; Manville 9-15 #1 | 170212117600 | Gamma Ray, Spontaneous Potential | Density |
| Keahey, J., Jr. #1 | 170212060900 | Gamma Ray, Spontaneous Potential | Density |
| Louisiana Green Fuels #1 | 170218801800 | Gamma Ray, Spontaneous Potential, Photoelectric Index | Density, Sonic, Nuclear Magnetic Resonance |
| Manville 32-13 #1 | 170212111300 | Gamma Ray, Spontaneous Potential, Photoelectric Index | Density, Sonic |
| Manville Forest Products Co. #1 | 170212089700 | Gamma Ray, Spontaneous Potential, Photoelectric Index | Density, Sonic |

#### *3.1.3.1 Annona Sand – Injection Zone*

The total porosity property was modeled for each of the three Annona Sand model layers. Table 9 shows the average modeled porosity along with a description of the variogram model used. Upscaled porosities in the Annona interval ranged from a minimum of 0.1298 P.U. to a maximum truncated value at 0.29 P.U. (Porosity Units).

**Table 9 Summary of modeled Annona porosity statistics and variogram model description**

| Interval | Min | Max | Mean | Std Dev | Variogram Type | AZI | Major Direction (ft) | Minor Direction (ft) | Vertical (ft) |
|---|---|---|---|---|---|---|---|---|---|
| Annona | 0.1298 | 0.3197 | 0.2376 | 0.0603 | Spherical | 90 | 3800035000 | 3800025000 | 47.75 |

#### *3.1.3.2 Tuscaloosa/Paluxy – Injection Zone*

The total porosity property is modeled for the Upper Tuscaloosa / Paluxy Injection Zone. Table 10 shows the average modeled porosity along with a description of the variogram model used in the

Upper Tuscaloosa (Upper Interval).

**Table 10 Summary of modeled Upper Tuscaloosa (Upper Interval) Zones A-G porosity statistics and variogram model description**

| Interval | Min | Max | Mean | Std Dev | Variogram Type | AZI | Major Direction (ft) | Minor Direction (ft) | Vertical (ft) |
|---|---|---|---|---|---|---|---|---|---|
| Upper Tuscaloosa A | 0.0769 | 0.3155 | 0.1905 | 0.0558 | Spherical | 0 | 37750 | 37750 | 21.8 |
| Upper Tuscaloosa B | Porosity held constant at 0.01 p.u. | | | | | | | | |
| Upper Tuscaloosa C | 0.0974 | 0.5823 | 0.2147 | 0.0625 | Spherical | 0 | 20000 | 20000 | 10 |
| Upper Tuscaloosa D | Porosity held constant at 0.01 p.u. | | | | | | | | |
| Upper Tuscaloosa E | 0.0821 | 0.2916 | 0.1904 | 0.0533 | Spherical | 0 | 25000 | 25000 | 10 |
| Upper Tuscaloosa F | Porosity held constant at 0.01 p.u. | | | | | | | | |
| Upper Tuscaloosa G | 0.0973 | 0.3919 | 0.1847 | 0.0537 | Spherical | 0 | 50000 | 50000 | 10 |

Table 11 shows the average modeled porosity along with a description of the variogram model used in the Upper Tuscaloosa (Lower Interval).

**Table 11 Summary of modeled Upper Tuscaloosa (Lower Interval) Zones H-MTS porosity statistics and variogram model description**

| Interval | Min | Max | Mean | Std Dev | Variogram Type | AZI | Major Direction (ft) | Minor Direction (ft) | Vertical (ft) |
|---|---|---|---|---|---|---|---|---|---|
| Upper Tuscaloosa H | 0.1011 | 0.3556 | 0.2089 | 0.05 | Spherical | 0 | 37750 | 37750 | 24.8 |
| Upper Tuscaloosa I | Porosity held constant at 0.01 p.u. | | | | | | | | |
| Upper Tuscaloosa J | 0.087 | 0.327 | 0.1953 | 0.0562 | Spherical | 0 | 37750 | 37750 | 40.5 |
| Upper Tuscaloosa K | Porosity held constant at 0.01 p.u. | | | | | | | | |
| Upper Tuscaloosa L | 0.0983 | 0.3723 | 0.1976 | 0.0566 | Spherical | 0 | 37750 | 37750 | 40.3 |
| Middle Tuscaloosa Shale | Porosity held constant at 0.01 p.u. | | | | | | | | |

For both the Paluxy P-2 and P-3 Sand intervals, the average porosity value observed at the single penetration point, the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841), was set as the constant porosity value for each such channel system within the Area of Review. Additional data, to be acquired during the drilling and testing of the injection and monitor wells, is expected to refine the determination and distribution of porosity within the Paluxy channels.

**Table 12 Summary of modeled porosity-constant values used in the modeled channels for both Paluxy 2 and Paluxy 3 Sands**

| Interval | Porosity Used Inside of the Channel | Porosity Used Outside of the Channel |
|---|---|---|
| Paluxy 2 | 0.23 p.u. | 0.01 p.u. |
| Paluxy 3 | 0.19 p.u. | 0.01 p.u. |

Appendix 5 contains porosity displays for each layer within the three modeled intervals, including both histograms as well as the final modeled property distribution for each layer.

## 3.2 PERMEABILITY

Permeability is defined as the capacity of a porous media to transmit fluids (Amyx et al., 1960). High connectivity of the pore spaces provides the pathway for fluids or gases to efficiently move through rock, in either direction (vertical or horizontal). Absolute permeability is an intrinsic property of porous materials and governs the ease with which fluids move through hydrocarbon - bearing reservoirs, aquifers, gravel packs and filters. When two or more fluids are present within the pore space, the immiscible displacement of one fluid by another affects the speed at which each fluid flows within the porous space (*i.e.*, relative permeability). The immiscible displacement of brine by supercritical carbon dioxide, which occurs when it is injected into an aquifer, is a physical process that occurs in addition to the miscible interaction of carbon dioxide and brine (the dissolution of one phase into another, depending on pressure and temperature conditions).

To model the supercritical carbon dioxide – brine displacement, absolute permeability is first measured under representative *in-situ* conditions on core samples. Absolute permeability is a function of porosity, irreducible wetting phase saturation, displacement or threshold pressure corresponding to a pore throat radius, and basic pore size characteristics. Since porosity dominates the pore size characteristics more than any other textural component, a porosity-permeability correlation can be used to estimate permeability from total log porosity for each injection zone.

### 3.2.1 Methodology

Absolute permeability is described by Darcy's Law. Calibration can be obtained from a range of sources: core measurements (plug scale), NMR measurements (log resolution), Formation

Pressure mobilities (connected flow units) and Drill Stem / Formation Pressure Fall-off Tests (zones open to testing for flow). The following equation is an adapted form of Darcy's Law, which assumes no gravitational forces and a homogeneously permeable medium:

$$Q = -\frac{kA}{\mu}\frac{\delta p}{\delta L}$$

Where:

$Q$ = volumetric flow in $cm^3/s$

$k$ = permeability in Darcy

$A$ = cross-sectional area in $cm^2$

$\mu$ = viscosity in centipoise

$\delta p$ / $\delta L$ = Pressure drop per unit length in atm/cm

Core permeability measurements often result in a wide range of absolute permeability measurements per porosity class. The range of permeability variations observed in each porosity class can be explained by variations in mineralogy, facies, and clay type. This can be addressed by rock typing where sufficient calibration data is available.

Permeability measurements were performed on whole core and rotary sidewall core samples obtained from the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). The core data was used to evaluate absolute and relative permeabilities for the project site. Analogous regional core (total) porosity and permeability data were also obtained from the SPDA database.

Core ambient permeability measurements were stress-corrected for the reservoir conditions encountered in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). The stress-corrected core measured permeability is plotted on the y-axis on a logarithmic scale and core porosity on the x-axis on a linear scale in Figure 13. An initial porosity-permeability transform was derived with the objective of preserving average permeabilities (and hence k*h) between upscaled reservoir model properties and the original core data using the "Swanson Averaging

Method" (Swanson, 1981). The Swanson Averaging Method corrects for the systematic underestimation of permeability resulting from the arithmetic averaging of the permeabilities. Since a geometric average would systematically overestimate permeabilities, the Swanson Average Method results in a permeability average that is more representative in the upscaled units.

The core data is first divided into porosity bins and a histogram of the permeability values found within each porosity bin is generated. The representative permeability is then determined per each quantile *(i.e.*, namely 10$^{th}$, 50$^{th}$ and 90$^{th}$ percentile) from each histogram. The Swanson Average Method permeability is then calculated as for each porosity bin as:

$$K_{Swanson} = 0.3K_{10} + 0.4K_{50} + 0.3K_{90}$$

where $K_{10}$ is the permeability for the 10$^{th}$ quantile, $K_{50}$ is the permeability for the 50$^{th}$ quantile and $K_{90}$ is the permeability for the 90$^{th}$ quantile within each porosity bin. A power law regression is drawn through the plotted Swanson Average Method – derived permeability points. A power law is often used as it is more representative of the natural porosity-permeability relationship.

#### *3.2.1.1 Annona Sand – Injection Zone 1*

The permeability property was modeled following porosity in the Annona Injection Zone (#1).

Table 13 presents the Annona Injection Zone *regional porosity-permeability transform* that was used to initially populate the Dynamic Model.

**Table 13 Initial and adjusted Annona regional transform**

| Injection Zones (Reservoirs) | Porosity-Permeability Transform |
|---|---|
| Annona – Regional Transform | Permeability (md) = 1.0E7 * (Porosity(%) ^6.5705) |
| Annona – Adjusted Transform to Match Falloff Test | Permeability (md) = 1.0E7 * (Porosity(%) ^6.05) |

The initial regional transform was adjusted so that permeability-thickness agreed with average permeability-thickness derived from the results of the Annona Injection Zone fall-off test conducted in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). A summary of the injection / fall-off testing / analysis of the Annona Injection Zone is included in **Module A**.

The Dynamic Model permeability was adjusted to a final transform following the following steps:

- A net-to-gross value was applied to each model layer, as needed, so that the modeled net thickness conformed to the petrophysical data and the Static Model.
- The regional permeability-porosity transform was adjusted so the model permeability-net thickness agreed with permeability-thickness values determined from pressure fall-off testing conducted in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841).
- The adjusted transform was then applied to all cells in the Annona model. The adjusted porosity-permeability transform for the Annona Injection Zone is presented in Table 13, above.

The adjusted permeability-thickness (Kh) was verified using the Dynamic Model to simulate an injection and shut-in (fall-off) pressure transient response at the location of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). The simulated model response was then analyzed using pressure transient analysis (PTA) methods. The Kh from the simulated response was compared to the Kh determined from PTA of the measured fall-off in the Annona Injection Zone. Kh from the simulated model response compared favorably to the actual PTA response of the Annona Sand injection / fall-off tests conducted in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841).

Figure 14 presents a cross-plot of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) core porosity-permeability values, the regional porosity-permeability model transform, and the final adjusted porosity-permeability transform used in the Annona Injection Zone Dynamic Model. The open circles are the porosity-permeability values derived from core samples in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). In Figure 14, the solid black line is the regional porosity-permeability transform, the solid “points” on the curve are the adjusted porosity-permeability values for the three layers in the Annona Dynamic Model, and the dashed blue line is the final adjusted regional porosity-permeability transform.

Table 14 shows the original and transformed properties used in the Annona Injection Zone Dynamic Model. The adjusted Kh in the Annona interval is 1,740 md-ft within a 2,500-foot radius of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). Adjusted transmissibility derived from permeability-thickness is 2,731 md-ft/cp, using a formation fluid viscosity of 0.637

centipoise. Transmissibility from the PTA of the Annona fall-off test is 2,643 md-ft/cp and represents a good match.

**Table 14 Annona Injection Zone - Original and Adjusted Permeability Values Within a ~2,500 Foot Radius Around the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841)**

| Layer | PHI | Regional Perm (md) | Gross Thickness (ft) | KH (md-ft) | N/G | Hnet (ft) | KH (md-ft) | KH/u (md-ft/cp) | K Adjusted (md) | KH Adj Perm and NG (md-ft) | Adjusted KH/u (md-ft/cp) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.2595 | 231 | 13.0 | 2,997 | 1.000 | 13.00 | 2,997 | 4,704 | 41.2 | 535.1 | 840 |
| 2 | 0.2895 | 402 | 13.0 | 5,231 | 0.300 | 3.90 | 1,569 | 2,464 | 71.9 | 280.3 | 440 |
| 3 | 0.2889 | 398 | 13.0 | 5,176 | 1.000 | 13.01 | 5,176 | 8,125 | 71.0 | 924.3 | 1451 |
| | | 344 | 39 | 13,404 | | 30 | 9742 | 21,042 | | 1,740 | 2,731 |

Appendix 6 presents the spatial porosity and permeability distribution, adjusted for net-to-gross, for the layers in the Annona Dynamic Model.

#### *3.2.1.2 Upper Tuscaloosa / Paluxy – Injection Zone 2*

The permeability property is modeled following porosity in the Upper Tuscaloosa / Paluxy Injection Zone (#2). Table 15 presents the Upper Tuscaloosa *regional porosity-permeability transform* that was used to initially populate the Upper Tuscaloosa Dynamic Model.

**Table 15 Initial and Adjusted Upper Tuscaloosa / Paluxy Regional Transforms**

| Injection Zones (Reservoir Intervals) | Porosity-Permeability Transform |
|---|---|
| Upper Tuscaloosa – Regional Transform | Permeability (md) = 1.0E7 * (Porosity(%)^6.5705) |
| Upper Tuscaloosa – Upper Interval Transform Adjusted to PTA | Permeability (md) = 1.0E7 * (Porosity(%)^6.23) |
| Upper Tuscaloosa. – Lower Interval / Paluxy Transform Adjusted to PTA | Permeability (md) = 1.0E7 * (Porosity(%) ^6.44) |

The regional porosity-permeability transform was adjusted by net-to-gross values assigned to each layer in the Upper Tuscaloosa Dynamic Model. The regional transform was adjusted so that the permeability-thickness agreed with the average permeability-thickness derived from the Upper Tuscaloosa injection / fall-off testing / analysis, a summary of which is included in **Module A**.

The final Upper Tuscaloosa Dynamic Model permeability was adjusted following these steps:

- A net-to-gross value was applied to each model layer as needed so the model net thickness conformed to the petrophysical data and Static Model.
- The regional permeability-porosity transform was adjusted so the model Kh agrees with the Kh values determined from pressure fall-off testing conducted in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841).
- The adjusted transform was then applied to all cells in the Upper Tuscaloosa model. The adjusted porosity-permeability transforms for the Upper Tuscaloosa (Upper Interval) and the Upper Tuscaloosa (Lower Interval) / Paluxy PTA test intervals are presented in Table 15, above.
- For modeling purposes, the adjusted porosity-permeability transform used for the Upper Tuscaloosa (Lower Interval) was also applied to the Paluxy layers in the Dynamic Model.

The adjusted Kh was verified using the Dynamic Model to simulate an injection and shut-in (fall-off) pressure transient response. The simulated response was analyzed using pressure transient analysis (PTA) methods. The Kh from the simulated response was compared to the Kh determined from PTA of the measured fall-off in the Upper Tuscaloosa intervals. Permeability-thickness (Kh) from the simulated model response compared favorably to the actual PTA response of the Upper Tuscaloosa and Paluxy injection / fall-off tests conducted in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841).

Figure 15 presents a cross plot of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) core porosity-permeability, the regional porosity-permeability model and the final adjusted porosity-permeability used in the Upper Tuscaloosa (Upper Interval) Dynamic Model. The open circles in the plot are the porosity-permeability values derived from core measurements in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). The solid black line is the regional porosity-permeability transform, the solid "points" on the curve are the adjusted porosity-permeability values for the layers in the Upper Tuscaloosa / Paluxy Dynamic Model, and the dashed blue line is the adjusted regional porosity-permeability transform.

Table 16 presents the original and transformed properties used in the Upper Tuscaloosa (Upper Interval) Dynamic Model. Within a 2,500-foot radius of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841), the adjusted average permeability-thickness in the Upper Tuscaloosa (Upper Interval) is 4,968 md-ft. The adjusted transmissibility derived from Kh is 10,153 md-ft/cp, using a viscosity of 0.52 centipoise for the native formation brine. PTA data indicated the transmissibility derived from the fall-off tests of the Upper Tuscaloosa (Upper Interval) layers 2 through 23 ranged from 7,160 and 11,364 md-ft/cp. The transmissibility modeled in these same layers was 8,997 md-ft/cp. Model layers 25 through 29 were not included in the fall-off tests of the upper three intervals conducted in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841); for modeling, the transmissibility for layers 25 through 29 employed the Upper Tuscaloosa (Upper Interval) adjusted transform.

Appendix 7 presents the spatial porosity and permeability distribution, adjusted for net-to-gross, for the 29 layers in the Upper Tuscaloosa (Upper Interval) Dynamic Model.

Figure 16 presents a cross plot of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) core porosity-permeability, the regional porosity-permeability model, and the final adjusted porosity-permeability used in the Upper Tuscaloosa (Lower Interval) Dynamic Model. The open circles in the plot are the porosity-permeability values derived from core measurements in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). The solid black line is the regional porosity-permeability transform, the solid “points” on the curve are the adjusted porosity-permeability values for the layers in the Upper Tuscaloosa (Lower Interval) / Paluxy Dynamic Model, and the dashed blue line is the adjusted regional porosity-permeability transform.

Table 17 presents the original and transformed properties used in the Upper Tuscaloosa (Lower Interval) / Paluxy Dynamic Model. The adjusted Kh in the Tuscaloosa is 7,290 md-ft within a 2,500-foot radius of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). Adjusted transmissibility derived from permeability-thickness is 15,534 md-ft/cp, using a viscosity of 0.525 centipoise for the formation brine. A review of the fall-off test PTA of the Upper Tuscaloosa (Lower Interval) / Paluxy layers 1 through 19 yields an estimated transmissibility of 13,174 md-ft/cp.

**Table 16 Upper Tuscaloosa (Upper Interval) - Original and Adjusted Permeability Values Within a ~2,500 Foot Radius Around the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841)**

| Layer | PHI | Regional Perm (md) | Gross Thickness (ft) | KH (md-ft) | N/G | Hnet (ft) | KH (md-ft) | KH/u (md-ft/cp) | K Adjusted (md) | KH Adj Perm and NG | KH/u adj Perm and NG | Top (TVDSS) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.0000 | 406 | 705.9 | | | | | | | | | 4,110.5 |
| 2 | 0.1529 | 231.50 | 11.6 | 2683 | 0.39244 | 45.46 | 13,038 | 25,073 | 68.5 | 311.5 | | 4,816.5 |
| 3 | 0.2600 | 215.32 | 11.6 | 2493 | 0.39244 | | | | 63.7 | 289.5 | 2911 | 4,828.1 |
| 4 | 0.2398 | 126.31 | 11.6 | 1463 | 0.39244 | | | | 37.4 | 169.8 | | 4,839.6 |
| 5 | 0.2654 | 241.97 | 11.6 | 2804 | 0.39244 | | | | 71.6 | 325.6 | | 4,851.2 |
| 6 | 0.2295 | 94.56 | 11.6 | 1095 | 0.39244 | | | | 28.0 | 127.1 | | 4,862.8 |
| 7 | 0.2289 | 98.42 | 11.6 | 1140 | 0.39244 | | | | 29.1 | 132.3 | | 4,874.4 |
| 8 | 0.1891 | 28.40 | 11.6 | 329 | 0.39244 | | | | 8.4 | 38.2 | | 4,886.0 |
| 9 | 0.1906 | 28.85 | 11.6 | 334 | 0.39244 | | | | 8.5 | 38.8 | | 4,897.5 |
| 10 | 0.1879 | 25.83 | 11.6 | 299 | 0.39244 | | | | 7.6 | 34.7 | | 4,909.1 |
| 11 | 0.1944 | 34.32 | 11.6 | 397 | 0.39244 | | | | 10.2 | 46.1 | | 4,920.7 |
| 12 | 0.0000 | 0.10 | 0.0 | 0 | | | | | 0.0 | 0.0 | | 4,932.3 |
| 13 | 0.0000 | 210.26 | 0.0 | 0 | 0.716 | 23 | 10217 | 19,647 | 62.2 | 0.0 | | 4,954.4 |
| 14 | 0.2733 | 296.90 | 8.0 | 2375 | 0.716 | | | | 87.8 | 503.0 | 4161 | 4,962.4 |
| 15 | 0.2826 | 354.48 | 8.0 | 2839 | 0.716 | | | | 104.9 | 601.3 | | 4,970.4 |
| 16 | 0.2731 | 287.50 | 8.0 | 2303 | 0.716 | | | | 85.1 | 487.7 | | 4,978.5 |
| 17 | 0.2793 | 337.41 | 8.0 | 2699 | 0.716 | | | | 99.8 | 571.6 | | 4,986.5 |
| 18 | 0.0000 | 0.10 | 0.0 | 0 | | | | | 0.0 | 0.0 | | 4,994.5 |
| 19 | 0.2294 | 106.29 | 12.6 | 1334 | 0.409 | 26 | 8264 | 15,892 | 31.4 | 161.6 | | 5,035.4 |
| 20 | 0.2472 | 157.77 | 12.5 | 1980 | 0.409 | | | | 46.7 | 239.9 | 1925 | 5,048.0 |
| 21 | 0.2385 | 122.27 | 12.5 | 1534 | 0.409 | | | | 36.2 | 185.9 | | 5,060.5 |
| 22 | 0.2030 | 44.36 | 12.5 | 556 | 0.409 | | | | 13.1 | 67.4 | | 5,073.0 |
| 23 | 0.2633 | 227.80 | 12.6 | 2859 | 0.409 | | | | 67.4 | 346.3 | | 5,085.6 |
| 24 | 0.0000 | 0.10 | 0.0 | 0 | | | | | 0.0 | 0.0 | | 5,098.1 |
| 25 | 0.1832 | 21.29 | 15.9 | 339 | 0.256 | 20 | 7931 | 15,253 | 6.3 | 25.7 | | 5,119.7 |
| 26 | 0.2043 | 46.64 | 15.9 | 743 | 0.256 | | | | 13.8 | 56.3 | 1156 | 5,135.6 |
| 27 | 0.2657 | 253.16 | 15.9 | 4030 | 0.256 | | | | 74.9 | 305.5 | | 5,151.5 |
| 28 | 0.2212 | 88.68 | 15.9 | 1413 | 0.256 | | | | 26.2 | 107.1 | | 5,167.5 |
| 29 | 0.2235 | 88.28 | 15.9 | 1406 | 0.256 | | | | 26.1 | 106.6 | | 5,183.4 |
| | | | | | | | | | | | | 5,199.3 |
| | | | 290.2 | 39450 | | 114.5 | 39,450 | 75,865 | 1047 | 4968 | 10,153 | |

**Table 17 Upper Tuscaloosa (Lower Interval) / Paluxy - Original & Adjusted Permeability Values Within a ~2,500 Ft. Radius Around the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841)**

| Layer | PHI | Regional Perm (md) | Gross Thickness (ft) | KH (md-ft) | N/G | Hnet (ft) | KH (md-ft) | KH/u (md-ft/cp) | K Adjusted (md) | KH Adj Perm and NG | KH/u adj Perm and NG | KH/u adj Perm and NG | Top (TVDSS) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.2457 | 136.570 | 15.0 | 2,050 | 0.68 | | | | 85.4 | 870.7 | | 134 | 5209.3 |
| 2 | 0.2715 | 263.419 | 15.0 | 3,954 | 0.68 | 30.60 | 4,707 | 9,051 | 164.6 | 1,679.2 | 5603 | 742 | 5224.3 |
| 3 | 0.2102 | 61.449 | 15.0 | 922 | 0.68 | | | | 38.4 | 391.7 | | 1350 | 5239.3 |
| 4 | 0.0000 | 0.000 | 15.0 | 0 | 0.00 | | | | 0.0 | 0.0 | | 1958 | 5254.3 |
| 5 | 0.0000 | 0.000 | 15.0 | 0 | 0.00 | | | | 0.0 | 0.0 | | 2566 | 5269.3 |
| 6 | 0.0000 | 0.000 | 47.0 | 0 | 0 | | | | 0.1 | 0.0 | | 3174 | 5284.3 |
| 7 | 0.2878 | 389.178 | 19.8 | 7,705 | 0.49 | | | | 243.2 | 2,343.0 | | 3782 | 5331.3 |
| 8 | 0.2236 | 94.530 | 19.8 | 1,872 | 0.49 | 28.90 | 6,623 | 12,736 | 59.1 | 569.2 | 7884 | 4390 | 5351.1 |
| 9 | 0.2596 | 203.801 | 19.8 | 4,035 | 0.49 | | | | 127.4 | 1,226.9 | | 4998 | 5370.9 |
| 10 | 0.0000 | 217.648 | 19.8 | 0 | 0.49 | | | | 136.0 | 0.0 | | 5606 | 5390.7 |
| 11 | 0.0000 | 56.918 | 19.8 | 0 | 0.49 | | | | 35.6 | 0.0 | | 6214 | 5410.5 |
| 12 | 0.0000 | 0.000 | 24.3 | 0 | | | | | 0.1 | 0.0 | | 6822 | 5430.3 |
| 13 | 0.2417 | 130.308 | 8.9 | 1,159 | 0.49 | 8.66 | 2999 | 5,767 | 81.4 | 352.5 | 1740 | 7430 | 5454.6 |
| 14 | 0.2575 | 204.109 | 8.9 | 1,816 | 0.49 | | | | 127.6 | 552.1 | | 8038 | 5463.5 |
| 15 | 0.0100 | 0.100 | 186.6 | 19 | 1.000 | | | | 0.1 | 11.7 | | 8646 | 5472.4 |
| 16 | 0.0100 | 0.100 | 24.3 | 2 | 1.000 | | | | 0.1 | 1.5 | | 9254 | 5659.0 |
| 17 | 0.0100 | 0.100 | 33.4 | 3 | 1.000 | | | | 0.1 | 2.1 | | 9862 | 5683.3 |
| 18 | 0.0000 | 58.585 | 30.3 | 0 | 1.000 | | | | 36.6 | 0.0 | | 10470 | 5716.8 |
| 19 | 0.1171 | 15.058 | 17.0 | 256 | 1.000 | 17 | 256 | 492 | 9.4 | 159.9 | 307 | 11078 | 5747.1 |
| | | | | | | | | | | | | 11382 | 5764.1 |
| | | | 540 | 21,743 | | 85 | 14,584 | 28,047 | | 7,290 | 15,534 | | |

Appendix 8 presents the spatial porosity and permeability distribution, adjusted for net-to-gross, for the 19 layers in the Upper Tuscaloosa (Lower Interval) / Paluxy Dynamic Model.

## 3.3 ROCK COMPRESSIBILITY

Compressibility is a material property that describes the change in volume induced in the material by an applied stress. The reservoir can undergo pore volume inflation (during fluid injection) or depletion (during fluid withdrawal) pressure regimes. Individual formation components respond to applied stresses (i.e., grains, matrix and fluids within the pore space) as well as the combination of all components, through grain contacts and the interaction between fluid flow and solids deformation: *i.e.*, the poro-elastic response (Fetter, 1988). Individual component compressibility values (grain and bulk compressibilities) and fluid phase compressibility are either measured at the lab under laboratory conditions or calculated using a frame modulus. When three fluid phases are present, the total (or bulk) compressibility is calculated from the individual components as:

$$c_t = c_f + S_o c_o + S_w c_w + S_g c_g$$

where:

| | | |
|---|---|---|
| $c_t$ | = | total compressibility ($psi^{-1}$) |
| $c_f$ | = | formation compressibility($psi^{-1}$) |
| $S_o$ | = | oil saturation (fraction) |
| $c_o$ | = | oil compressibility ($psi^{-1}$) |
| $S_w$ | = | water saturation (fraction) |
| $c_w$ | = | water compressibility ($psi^{-1}$) |
| $S_g$ | = | gas saturation (fraction) |
| $c_g$ | = | gas compressibility ($psi^{-1}$) |

### 3.3.1 Formation Compressibility

For water-filled reservoirs, in which $S_w$ equals 1, compressibility can be simplified to:

$$c_t = c_f + c_w$$

The change in porosity is a result of a change in the elastic properties (or moduli) of the framework of the rock (*i.e.*, the grains, cements and contacts). A large pore volume compressibility transfers pore pressure more effectively across the pore system, enabling fluids to percolate through. The rate of change in pore volume is influenced by textural components of different rock types and is quantified by pore volume compressibility ($c_f$). Compressibility measurements obtained in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) are shown in Table 18.

The model adjusts the compressibility of the rock framework based on the grid block pressure.

Reveal calculates saturation and fluid compressibility, which are a function of pressure and temperature, for each cell, at each time step in the model. Total compressibility ($c_t$) changes dynamically as pressure and temperature changes in each grid cell. The Dynamic Model calculates rock compressibility based on the reference compressibility, porosity, and pressure in each cell.

**Table 18 Rock Compressibility for the Injection Zones**

| Injection Zones | Formation (Rock) Compressibility |
|---|---|
| Annona Sand (Injection Zone 1) | 3.1E-6 1/psi @ 2,000 psia |
| Upper Tuscaloosa / Paluxy (Injection Zone 2) | 2.87E-6 1/psi @ 2,166 psia |

### 3.3.2 Formation Fluid Compressibility, Density, and Viscosity

Brine compressibility ($c_b$) represents the change in volume ($\partial V_b$) of the brine, relative to initial volume ($V_b$), for a given pressure change ($\partial p$) at a constant temperature.

$$c_b = \left(1/V_b\right)\left(\partial V_b/\partial p\right)$$

Compressibility can also be defined based on the change in density ($\partial V_b$) of the brine, relative to initial density ($\rho_i$), for a given pressure change ($\partial p$) at constant temperature, assuming mass is conserved.

$$c_b = \left(1/\rho_i\right)\left(\partial \rho/\partial p\right)$$

Reference formation fluid densities used in the model are from site-specific sampling in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). Sample fluid density and model initialization data for each model are shown below in Table 19, below. This density yields a pressure gradient in line with the measured pressure in fall-off tests and regional pressure trends.

The Reveal model uses an internal correlation to estimate water viscosity as described in the User's Manual (Appendix 1). The viscosity calculation is also dependent upon pressure, temperature and density.

**Table 19 Initial Water Density and Zone Pressure**

| | PTA | | | Model Initialization | | | | | | Model Input | | Water Sample | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Falloff | Grad | | Center GB | Initial | Pr Grad | Temp | Temp Grad | Insitu Water Density | | Density | |
| | Depth (md) | $P_{last}$ | psi/ft | | Depth (ft TVDss) | (psi) | (psi/ft) | (F) | (F/ft + 67) | ppm | SG @ StandCond | SG @ 25( | Sample Depth |
| **Annona** | 4,149 | 1,953 | **0.47** | Lyr1 | 4,051 | 1,919 | **0.47** | 130 | 0.016 | 87,083 | 1.06 | 1.07 | 4149 - 4184 ft |
| **Upper** | 4,913 | 2,197 | **0.45** | Lyr2 | 4,832 | 2,175 | **0.45** | 143 | 0.016 | 143,687 | 1.09 | 1.09 | 4913 - 4948 ft |
| **Lower** | 5,250 | 2,389 | **0.46** | Lyr1 | 5,217 | 2,347 | **0.45** | 150 | 0.016 | 143,687 | 1.09 | 1.09 | 5250 - 5343 ft |

Table 20, shown below, shows the range of water viscosities calculated at nominal pressure and temperature conditions for each of the three injection layers.

**Table 20 Initial Modeled Brine Fluid Properties at Nominal Conditions**

| Zone | Model Initialization | | | | | Model Input | | Viscosity |
|---|---|---|---|---|---|---|---|---|
| | | Center GB | Initial | Temp | Temp Grad | In-situ Water Density | | |
| | | **Depth (TVD)** | (psi) | (F) | (F/ft + 67) | ppm | SG @ Std. Cond | (cp) |
| **Annona** | Lyr1 | 4,051 | 1,919 | 130 | 0.016 | 87,083 | 1.06 | 0.609 |
| **Upper UT** | Lyr2 | 4,832 | 2,175 | 143 | 0.016 | 143,687 | 1.09 | 0.547 |
| **Lwr UTP** | Lyr1 | 5,217 | 2,347 | 150 | 0.016 | 143,687 | 1.09 | 0.520 |

Fluid compressibility, density, and viscosity are a function of pressure and temperature. Therefore, a continuum of fluid property values is encountered throughout the modeled grid space.

- Figures presented in Appendix 9 illustrate the expected pressure and temperature distribution in the model grid.
- Figures presented in Appendix 10 illustrate the estimated fluid properties throughout the injection and post-injection periods for the primary injection layers.

## 3.4 CONSTITUTIVE RELATIONSHIPS

Relative permeability behavior and capillary trapping characteristics of the Upper Confining Zone and other impermeable boundaries are recognized as highly impactful to the capability to inject and immobilize supercritical carbon dioxide within the storage complex. A comprehensive review of experimental measurements of supercritical carbon dioxide / brine wettability in analogous sandstones supports the base-case assumption that the Annona Sand and the multiple sandstone reservoirs of the Upper Tuscaloosa and Paluxy intervals are water-wet and thus well suited to the immobilization of supercritical carbon dioxide via capillary trapping.

Nevertheless, uncertainties attributable to wettability/contact angle, capillary pressure (and capillary trapping), irreducible water saturation, relative permeability (and relative permeability hysteresis between drainage and imbibition processes), and impermeable boundary capillary entry pressure do exist. Further refinement of these properties derived from additional core analyses from both the Upper Confining Zone and other impermeable boundaries will be achieved during the drilling and testing of the proposed injection wells. The results of these core analyses will be incorporated into any revisions of the modeling submitted for the permit to commence injection.

Relative permeability and capillary pressure / irreducible water saturation are defined in the Dynamic Model using Brooks-Corey parameters and correlations.

**Table 21 Relative Permeabilities and Saturation Factor Inputs Into *Reveal* Software Calculations**

| Phase | Critical Fluid Saturation | Brooks-Corey Endpoint | Brooks-Corey Exponent |
|---|---|---|---|
| Brine | $S_{wc} = 0.2$ | 0.7 | 1.7 |
| Gas | $G_{cs} = 0.0$ | 0.7 | 2.3 |

Capillary forces in a subsurface reservoir (whether filled with hydrocarbons or a saline aquifer intended for supercritical carbon dioxide sequestration) are the result of multiple factors, including surface and interfacial tensions of both the rock matrices and the fluids contained within the pore system of the rock. The pore network, both in geometry and pore throat size, represents a second critical component. Finally, capillary forces are also impacted by the wetting characteristics of the system. The capillary pressure of a system is the difference in pressure between the fluid originally within the formation and a fluid (in this case, supercritical carbon dioxide, which exhibits certain physical properties of a fluid) that it comes into contact with.. The ability of one fluid to displace another within porous rock can either be hindered or aided by capillary pressure (Ahmed, 2010). Table 22 illustrates the inputted capillary pressure data.

**Table 22 Capillary Pressure Curve Data Inputs Into *Reveal* Software Calculations**

| SW | Pc | | SW | Pc |
|---|---|---|---|---|
| 0.20 | 182.00 | | 0.60 | 2.88 |
| 0.20 | 63.80 | | 0.62 | 2.72 |
| 0.22 | 36.50 | | 0.64 | 2.58 |
| 0.24 | 24.90 | | 0.66 | 2.45 |
| 0.26 | 18.70 | | 0.68 | 2.34 |
| 0.28 | 14.70 | | 0.70 | 2.23 |
| 0.30 | 12.10 | | 0.72 | 2.13 |
| 0.32 | 10.20 | | 0.74 | 2.04 |
| 0.34 | 8.80 | | 0.76 | 1.96 |
| 0.36 | 7.70 | | 0.78 | 1.88 |
| 0.38 | 6.83 | | 0.80 | 1.81 |
| 0.40 | 6.13 | | 0.82 | 1.74 |
| 0.42 | 5.54 | | 0.84 | 1.68 |
| 0.44 | 5.05 | | 0.86 | 1.62 |
| 0.46 | 4.63 | | 0.88 | 1.56 |
| 0.48 | 4.27 | | 0.90 | 1.51 |
| 0.50 | 3.96 | | 0.92 | 1.46 |
| 0.52 | 3.69 | | 0.94 | 1.41 |
| 0.54 | 3.45 | | 0.96 | 1.37 |
| 0.56 | 3.24 | | 0.98 | 1.33 |
| 0.58 | 3.05 | | 1.00 | 1.29 |

It is well understood that high capillary entry pressure associated with the extremely low permeability of the confining and containment layers will very effectively counteract buoyancy forces and keep the injected supercritical carbon dioxide contained within the storage complex. This will be evaluated as a part of the planned core analysis program for the injection wells, as described in **Module D**.

## 3.5 BOUNDARY CONDITIONS

The horizontal surfaces above and below the model grids are modeled as impermeable, confining model pressure within the static model cube.

No faults have been identified within any of the confining or injection zones in the study area. A constant pressure boundary has been added to the perimeter of the entire Reveal grid system. This methodology mimics an infinite system along the grid edges.

The following assumptions were made with respect to the aquifer:

1) The aquifer acts as an “infinite” aquifer within the scale of the model.

2) The flux across the aquifer is assumed to be equal at all boundaries.

3) The model has an open interface with the surrounding aquifer. Thus, fluids can move, and pressure can transmit freely across the periphery of the model grid.

There is minimal pressure build-up at the edges of the grid.

## 3.6 INITIAL / STATIC CONDITIONS

Initial conditions for the model and each Injection Zone are provided in Table 19. Initial conditions are based upon data collected in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841), along with well data from offset (legacy) wells, regional data, and literature sources relevant to the proposed injection reservoirs.

The temperature gradient and its range of uncertainty used in the Reveal model were taken from published data and confirmed with data obtained in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). A gradient of 1.60° F / 100 feet and a mean annual surface temperature in Caldwell Parish of 67 °F was used in the Dynamic Model to estimate initial reservoir conditions.

Formation fluid densities used in the model are from site-specific water sampling in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). These samples were obtained via swabbing operations at the onset of individual perforation testing in the Stratigraphic Test Well. The fluid properties derived from each sample are reported in **Module A**.

Reported measured pressures and pressure gradients of certain Cretaceous formations are also available from several of the legacy wells drilled within the Area of Review. The wells include:

- Bass Enterprises, J. L. Keahey #1 (La SN165305) – located 2.4 miles to the northeast of the proposed project facility (Section 8 – Township 14N, Range 4E)
- Sampson Contour Energy EP, LLC, Blackstone Minerals #2 (La SN232452) – located 7.7 miles to the northwest of the proposed facility (Section 31 – Township 15N, Range 3E)
- G. Lea & Franks Petroleum Co. Olinkraft #1 (La SN122331) – located 9.3 miles to the northwest of the proposed facility (Section 24 – Township 15N, Range 2E)

The Sampson Contour Energy EP, LLC, Blackstone Minerals #2 (La SN232452), which recorded a total of fourteen pressure data points from below the top of the Lower Cretaceous Hosston Formation, exhibits an average pressure gradient of approximately 0.46 psi/foot of depth (the Hosston Formation is well below the Lower Confining Zone, the Lower Cretaceous Ferry Lake Anhydrite). The pressure data points obtained in the Bass Enterprises, J. L. Keahey #1 (La SN165305) were sampled from strata in the Lower Cretaceous Mooringsport and Hosston Formations. The calculated pressure gradient in the Mooringsport and Hosston strata as measured in the Bass Enterprises well is approximately 0.468 psi/ft. The pressure data points obtained in the G. Lea & Franks Petroleum Co. Olinkraft #1 (La SN122331) are from the Lower Cretaceous Rodessa and Hosston Formations (both of which are, stratigraphically, well below the Lower Confining Zone and exhibit an average pressure gradient of approximately 0.466 psi/ft.).

Original pore pressures were determined by extensive formation pore pressure testing, in both open and cased hole, in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). Numerous formation pore pressure measurements were obtained during open hole geophysical well logging using the Schlumberger PressureXpress (XPT) wireline tool (see **Module A**). Additionally, downhole surface readout gauges (and memory gauges) were used during injection / fall-off testing of the various proposed injection intervals. Reservoir pressures obtained by the Schlumberger XPT wireline tool and from the downhole surface readout gauges are reported in **Module A**.

Details on the estimated and derived initial reservoir conditions are presented in "*Section 2.0 – Site Characterization*" of the Project Narrative, submitted in **Module A.** Formation temperature, pore pressures, and brine salinity have been derived from the extensive data acquisition conducted in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). The initial reservoir conditions listed in Table 20 will be updated with data acquired during the drilling and testing of the proposed injection wells (see **Module D**). Additional whole core and rotary sidewall core data as well as the data obtained during the open hole geophysical well logging program will add to the site-specific database and will be used to update the model prior to start of injection. Significant disparities in the salinity or density of the formation fluids used in the model are not expected.

## 3.7 OPERATIONAL INFORMATION

The injection well completions will utilize completion technology that allows injection pressure and rate to be controlled at selected points (depths) in each injection well. This will allow for the optimization of injection deliverability while remaining well below the regulatory fracture pressure injection limitations of the EPA and LDNR, as well as the more restrictive requirements of CARB. To model this behavior, the Dynamic Model for the Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone #2) was divided into the Upper Tuscaloosa (Upper Interval) and the Upper Tuscaloosa (Lower Interval) / Paluxy. This division and grouping allows for two simpler, more robust, Dynamic Models as opposed to one much more complex model with multiple well completions and multiple injection pressure constraints.

The pressure and rate control points in the completions will occur at:

- the uppermost (1$^{st}$) Upper Tuscaloosa porous interval, which is Layer 1 in the Upper Tuscaloosa (Upper Interval) Dynamic Model; and
- the 5$^{th}$ porous Tuscaloosa interval, which is Layer 1 (and the uppermost porous interval) in the Upper Tuscaloosa (Lower Interval) / Paluxy Dynamic Model.

There are six “primary” porous intervals in the Upper Tuscaloosa Dynamic Models. The Upper Tuscaloosa (Upper Interval) Dynamic Model incorporates the first four (shallowest) primary Upper Tuscaloosa porous intervals, while the Upper Tuscaloosa (Lower Interval) / Paluxy Dynamic Model incorporates the deepest two primary Upper Tuscaloosa porous intervals as well as the Paluxy P-2 and P-3 Sands.

If, during the injection operation, there were to be no physical separation of the Upper and Lower intervals, such that all of the Upper Tuscaloosa porous intervals as well as the Paluxy porous intervals are commingled and in pressure communication, the maximum injection pressure of the entire commingled Upper Tuscaloosa / Paluxy interval would be constrained by the maximum injection pressure permitted across the shallowest Upper Tuscaloosa reservoir (Layer 1 of the Upper Tuscaloosa (Upper Interval); *i.e.*, 90% of its fracture gradient for EPA and LDNR, 80% for CARB). Because of the fracture pressure differential of the top layer of the two intervals relative to their depths, separating the Upper Tuscaloosa / Paluxy Dynamic Model into pressure-isolated Upper and Lower intervals (as proposed) increases the maximum permitted injection into the Lower Interval at a pressure that is over 230 psi higher than would otherwise be permitted into the Upper Interval. The result is a higher available injection rate capacity.

As indicated above, the Upper Tuscaloosa (Lower Interval) Model also includes three porous sandstones of the Lower Cretaceous Paluxy Formation (Paluxy P-1, P-2, and P-3 Sands). The Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) encountered the P-1, P-2, and P-3 Sands in the upper part of the Paluxy (prior to reaching total depth at 6,200 feet); several offset legacy test wells drilled deeper within the Area of Review penetrated other (additional) Paluxy sandstone channels as deep as 7,000 feet. One or more of these deeper Paluxy channel sands, which have been demonstrated to reach thicknesses in excess of 50 feet in the surrounding area, are likely to be encountered in the three proposed injection wells.

All modeling imposed a maximum injection pressure limit of 80% of a reservoir’s fracture pressure, consistent with the CARB LCFS Protocol. This limit is much more conservative than the 90% of a reservoir’s fracture pressure allowed for injection under 40 CFR §146.88(a). Note that these limits are placed on the absolute values of the fracture pressure, not on the incremental value between the initial reservoir pore pressure and fracture pressure values. This represents an additional level of safety and conservatism inherently set in the modeling included in this section. As it pertains to the highest modeled layer (Layer 1) within the Upper Interval of the Upper Tuscaloosa, the fracture pressure limit in the modeling was estimated to equate to depth times 0.83 psi/ft. The estimation of fracture pressure is discussed in Section 3.9 of this document.

## Annona Injection Zone (Injection Zone 1)

In the modeling of the Annona Injection Zone, which is proposed to be held in reserve, a single Annona Sand injection well was modeled for sequestration. This Annona Injection Well would be drilled to and reach total depth just beneath the base of the Annona Injection Zone. As such, the contemplated operation justifies a stand-alone Dynamic Model site-specific to the Annona.

The Annona Injection Zone consists of 3 model layers used in the Dynamic Model and focuses on the drilling and completion of one Annona Injection Well located adjacent to LGF W-S2 (Figure 1; the most southerly proposed injection well). For reference purposes, this proposed Annona Injection Well is designated the LGF W-S2A. At this location, the Annona Dynamic Model indicates an average injection capacity (at maximum permitted injection pressure) of 9.9 mmscfpd of supercritical carbon dioxide (equivalent to the daily injection of 523 metric tons / 577 US tons).

**Table 23 Operating Details – Annona Injection Zone**

| Operating Information | W-S2A |
|---|---|
| Location (global coordinates)<br>X<br>Y | 544,873.31<br>2,127,632.992 |
| Model coordinates (ft)<br>X<br>Y | 76,983<br>36,927 |
| No. of perforated intervals | 1 |
| Perforated interval (ft MSL)<br>Z top<br>Z bottom | 4,143<br>4,208 |
| Wellbore diameter (ft.) | 0.35 |
| Injection duration (years) | 20 |
| Injection rate (tons/day) * | 9.9 mmscfd<br>523 mt/day<br>577 USt/day |

**If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).*

**<u>Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone 2, including Upper and Lower Intervals)</u>**

Within the Upper Tuscaloosa (Upper Interval) Dynamic Model, there are four porous intervals consisting of twenty-five model layers. Wells LGF W-N1 and LGF W-N2 have slightly less injection potential due to the shallower depth at which the Upper Tuscaloosa formation is encountered, relative to LGF W-S2. Deeper injection depths all for higher bottomhole injection pressures and rates given the fracture pressure constraint.

**Table 24 Operating Details – Upper Tuscaloosa (Upper Interval)**

| Operating Information | W-N1 | W-N2 | W-S2 |
|---|---|---|---|
| Location (global coordinates)<br>X<br>Y | 553,645.080<br>2,120,695.202 | 553,236.430<br>2,133,289.792 | 544,873.31<br>2,127,632.992 |
| Model coordinates (ft)<br>X<br>Y | 70,045.202<br>27,654.92 | 82,639.792<br>28,063.57 | 76,983<br>36,927 |
| No. of perforated intervals | 4 | 4 | 4 |
| Perforated interval (ft MSL)<br>Z top to Z bottom | 4,630 to 4,736<br>4,770 to 4,806<br>4,851 to 4,905<br>4,944 to 5,014 | 4,653 to 4,757<br>4,793 to 4,824<br>4,881 to 4,929<br>4,968 to 5,048 | 4,955 to 5,061<br>5,097 to 5,126<br>5,179 to 5,230<br>5,260 to 5,337 |
| Wellbore diameter (ft.) | 0.35 | 0.35 | 0.35 |
| Injection duration (years) | 20 | 20 | 20 |
| Injection rate (tons/day) * | 12.4 mmscfd<br>652 mt/day<br>718 USt/day | 12.5 mmscfd<br>658 mt/day<br>725 USt/day | 15.1 mmscfd<br>794 mt/day<br>875 USt/day |

**If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).*

There are three porous intervals, consisting of 8 model layers, in the Upper Tuscaloosa (Lower Interval) / Paluxy Dynamic Model. Two intervals with six layers were modeled in the Lower Interval of the Upper Tuscaloosa, while one interval was modeled in the Paluxy, consisting of two model layers. In the Upper Tuscaloosa (Lower Interval) / Paluxy Dynamic Model, Wells LGF W-N1 and LGF W-N2 have slightly less maximum injection capacity due to their shallower depth relative to LGF W-S2 and will be operated at a slightly less injection rate than

LGF W-S2. Deeper injection depths allow for a higher injection pressure and rate but remain limited by the CARB-mandated 80% of fracture pressure constraint.

**Table 25 Operating Details – Upper Tuscaloosa (Lower Interval)/Paluxy**

| Operating Information | W-N1 | W-N2 | W-S2 |
|---|---|---|---|
| Location (global coordinates)<br>X<br>Y | 553,645.080<br>2,120,695.202 | 553236.430<br>2133289.792 | 544873.31<br>2127632.992 |
| Model coordinates (ft)<br>X<br>Y | 70,045.202<br>27,654.92 | 82639.792<br>28063.57 | 76983<br>36927 |
| No. of perforated intervals | 3 | 3 | 3 |
| Perforated interval (ft MSL)<br>Z top to Z bottom | 4,996 to 5,025<br>5,118 to 5,181<br>5,523 to 5,575 | 5,028 to 5,055<br>5,145 to 5,212<br>5,531 to 5,581 | 5,322 to 5,351<br>5,440 to 5,494<br>5,861 to 5,914 |
| Wellbore diameter (ft.) | 0.35 | 0.35 | 0.35 |
| Planned injection period.<br>Start<br>End | | | |
| Injection duration (years) | 20 | 20 | 20 |
| Injection rate (tons/day) * | 12.5 mmscfd<br>658 mt/day<br>725 USt/day | 12.5 mmscfd<br>658 mt/day<br>725 USt/day | 15.0 mmscfd<br>790 mt/day<br>870 USt/day |

**If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).*

## 3.8 FRACTURE PRESSURE AND GRADIENT

The methodology in this application for determining the fracture gradient pressure of the Injection Zones used the following equations as provided from (Jaeger et al., 2007):

$$Pr = \frac{1}{2}\frac{\left({}^{V_P}/_{V_S}\right)^2 - 2}{\left({}^{V_P}/_{V_S}\right)^2 - 1}$$

$$E = 2\rho V_S^2(1 + Pr)$$

$$\sigma_v = g \int_0^z \rho(z)dz$$

$$\sigma_h = \frac{Pr}{1 - Pr}(\sigma_v - \alpha PP) + \alpha P_0$$

Where:

$Pr$ = Poisson's ratio (provided in its dynamic expression in the above equations)

$V_P$ = Compressional wave velocity (the inverse of the compressional wave slowness log)

$V_S$ = Shear wave velocity (the inverse of the shear wave slowness log)

$E$ = Young's modulus (provided in its dynamic expression in the above equation)

$\rho$ = Rock density

$\sigma_v$ = Overburden stress

$g$ = Acceleration due to gravity

$z$ = Depth

$\sigma_h$ = Minimum horizontal stress

$\alpha$ = Poro-elastic coefficient (or Biot's constant)

$P_0$ = Pore pressure (or formation pressure)

The injection pressure envelope (safe operating injection limit) is determined from the fracture gradient. The fracture gradient is estimated using Kirsch's Solution for the formation breakdown pressure as defined in Haimson and Fairhurst (1970) and Zhang and Roegiers (2010).

$$P_{FPmax} = 3\sigma_{min} - \sigma_H - p - \sigma_T - T_O$$

Where:

$P_{FPmax}$ = the upper bound of the fracture pressure,

$\sigma_H$ = the maximum horizontal stress,

$\sigma_{min}$ = the minimum horizontal stress,

$p$ = the pore pressure,

$\sigma_T$ = the thermal stress and

$T_O$ = the tensile strength of the rock.

Zhang (2010) makes the statement that Eaton's method (Eaton, 1969) may presume pre-existing fractures in the formation as it neglects the tensile strength of a rock. The minimum stress is the minimum principal *in-situ* stress and typically equal to the fracture closure pressure (Zhang, 2010). Therefore, the following approximation for the estimate of fracture pressure would be:

$$FG = K * (\sigma_v - \alpha P_P) + \alpha P_P$$

Where

$FG$ = the fracture gradient,

$K$ = the stress ratio (for Eaton it is estimated using Poisson's ratio),

$\sigma_V$ = the vertical stress,

$\alpha$ = the Biot coefficient, and

$Pp$ = the pore pressure.

The vertical stress imposed by the lithostatic load is calculated from:

$$\sigma_V = \int_0^z \rho(z).g.dz$$

The Biot coefficient α is calculated from:

$$\alpha = 1 - \frac{C_g}{C_b}$$

Where

$\alpha$ = the Biot coefficient,

$C_g$ = the grain compressibility; and

$C_b$ = the bulk compressibility.

No indications of pre-existing fractures were observed during the drilling, coring, logging or testing of the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). Data used to search for the presence of such pre-existing fractures included the analyses of the recovered whole cores and also the analysis of the early time behavior from the pressure transient fall-off test data observed during the subsequent water injection well tests conducted in the Stratigraphic Test Well (**see Module A**). The injection pressure vs. injection rate data plots from the step-rate testing during active injection and the behavior of the shape of the fall-off data clearly indicate only matrix injection with no indication of formation breakdown.

Following the methodology presented by Zhang (2010), the lack of known pre-existing fractures validates the use of Kirsch's Solution for the calculation of the fracture breakdown pressure. This is then assumed as the base case for the reservoir model. Injection pressure details for the Annona Injection Zone (Injection Zone #1) Model are presented in Table 26.

**Table 26 Injection Pressure Details – Annona Sand Injection Zone (Injection Zone #1)**

| **Injection Pressure Details** | |
|---|---|
| Fracture gradient (psi/ft) | 0.83 psi/ft |
| Maximum injection pressure (80% of fracture pressure) (psi) | 2,762 |
| Elevation corresponding to maximum injection pressure (ft MSL) | 4,159 |
| Elevation at the top of the perforated interval (ft MSL) | 4,159 |
| Calculated maximum injection pressure at the top of the perforated interval (psi) | 2,744 |

The injection pressure details for the Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone #2) Model (both intervals) are presented in Table 27.

**Table 27 Injection Pressure Details – Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone #2 both intervals)**

| Injection Pressure Details – Upper Tuscaloosa (Upper Interval) | Well W-N1 | Well W-N2 | Well W-S2 |
|---|---|---|---|
| Fracture gradient (psi/ft) | 0.83 psi/ft | 0.83 psi/ft | 0.83 psi/ft |
| Maximum injection pressure (80% of fracture pressure) (psi) | 3,093 | 3,107 | 3,308 |
| Elevation corresponding to maximum injection pressure (ft MSL) | 4,658 | 4,680 | 4,982 |
| Elevation at the top of the perforated interval (ft MSL) | 4,658 | 4,680 | 4,982 |
| Calculated maximum injection pressure at the top of the perforated interval (psi) | 3,081 | 3,005 | 3,107 |
| **Injection Pressure Details – Upper Tuscaloosa (Lower Interval) / Paluxy** | **Well W-N1** | **Well W-N2** | **Well W-S2** |
| Fracture gradient (psi/ft) | 0.83 psi/ft | 0.83 psi/ft | 0.83 psi/ft |
| Maximum injection pressure (80% of fracture pressure) (psi) | 3,341 | 3,343 | 3,583 |
| Elevation corresponding to maximum injection pressure (ft MSL) | 5,032 | 5,035 | 5,329 |
| Elevation at the top of the perforated interval (ft MSL) | 5,032 | 5,035 | 5,329 |
| Calculated maximum injection pressure at the top of the perforated interval (psi) | 3,170 | 3,211 | 3,308 |

## 3.9 CHARACTERISTICS OF THE CARBON DIOXIDE STREAM

The carbon dioxide stream is sourced from the biofuels production facility and the associated power plant. Composition and other impurities that may be present in the stream are shown below.

**Table 28 Biorefinery $CO_2$ Stream Composition**

| | *Units* | *Biorefinery $CO_2$ Stream Only (Stream 4509)* |
|---|---|---|
| ***Normal Flow rate*** | lb./h | 138,911 |
| ***Pressure (at compressor discharge)*** | Psia | 2,248 |
| ***Temperature*** | F | 107 |

| *Composition* | | |
|---|---|---|
| *$H_2O$* | mol% | 0.00 |
| *Hydrogen* | mol% | 0.05 |
| *CO* | mol% | 0.34 |
| *$CO_2$* | mol% | 99.55 |
| *Nitrogen* | mol% | 0.00 |
| *Argon* | mol% | 0.004 |
| *Oxygen* | mol% | 0.00 |
| *HCl* | ppmv | 0.00 |
| *$H_2S$** | ppmv | 225 (EOR)/228 (SOR) |
| *COS* | ppmv | 1.00 |
| *HCN* | ppmv | 0.21 |
| *Ammonia* | ppmv | 0.00 |
| *Methane* | mol% | 0.02 |
| *Benzene* | mol% | 0.00 |
| *Ethylene* | mol% | 0.00 |
| *Ethane* | mol% | 0.00 |
| *Propene* | mol% | 0.00 |
| *Propane* | mol% | 0.00 |
| *i-Butane* | mol% | 0.00 |
| *1-Butene* | mol% | 0.00 |
| *n-Butane* | mol% | 0.00 |
| *$C_5$-$C_9$* | mol% | 0.00 |
| *$C_{10}$-$C_{19}$* | mol% | 0.00 |
| *$C_{20}$-$C_{35}$* | mol% | 0.00 |
| *$C_{36+}$* | mol% | 0.00 |
| *Methanol* | mol% | 0.01 |
| *Ethanol* | mol% | 0.00 |
| *$C_{3+}$ Alcohols* | mol% | 0.00 |
| *Formic Acid* | mol% | 0.00 |
| *$C_{2+}$ Acids* | mol% | 0.00 |
| ***TOTAL*** | mol% | 100.00 |

### Table 29 Power Plant $CO_2$ Stream Composition

| *Component* | *Units* | *Power Plant Stream* |
|---|---|---|
| Carbon Dioxide | mol% | 99.5 |
| Water Content | lbs./1MMSCF | 5 |
| Total Sulfur | ppb | <70 |
| Chlorine as HCL | ppb | <2.9 |

| | | |
|---|---|---|
| Carbon (element) | | NIL |
| Metals (V, K, Na, Hg, Fe) | | NIL |
| Arsenic | ppm | <0.1 |
| Lead | ppm | <0.2 |
| Iron | $mg/Nm^3$ | <0.003 |
| Nickel | ppb | <3.7 |
| Ammonia | ppb | <9 |
| Particulate Matter | | NIL |
| Hydrogen Cyanide | | NIL |
| Oxygen | mol% | <0.1 |
| Carbonyl | ppb | <2 |

### 3.9.1 Carbon Dioxide Density and Compressibility

All modeling presented in this submittal assumes 100 percent pure carbon dioxide. This is conservative as impurities tend to increase density of the injected carbon dioxide, thus reducing the buoyancy force. The carbon dioxide density and phase behavior are estimated using the Peng-Robinson Equation of State (EOS) (Robinson and Peng, 1978). The Peng-Robinson EOS is used throughout the petroleum and chemical industries to model the phase behavior and molar volume (density) of single and multi-component systems with carbon dioxide as a significant component.

The carbon dioxide critical pressure, and critical temperature used in the Peng-Robinson EOS (Table 30) for this application are consistent with values provided by the National Institute of Standards and Technology (NIST) for carbon dioxide.

Carbon dioxide density increases as pressure increases and decreases as temperature increases. Because of this relationship, the density of the carbon dioxide in each of the injection zones is similar. The density of the advancing plume, especially at its leading edge, is of interest. The density contrast between the carbon dioxide and *in-situ* saline formation water, along with the formation dip, influences the lateral extent and rate of potential plume expansion over time.

**Table 30 Critical Property Inputs for carbon dioxide**

| Parameter | Input Unit |
|---|---|
| Critical temperature (Tc) | 304.18 ˚K ( 87.854 ˚F) |
| Critical pressure (Pc) | 73.8 bar (1,070.379 psi) |

The graphs contained in Appendix 11 present the carbon dioxide density (graphs) estimated for each of the injection zones at the initialization temperature and range of pressures. The graphs compare estimated carbon dioxide density calculated using the Peng-Robinson EOS, implemented in the Reveal software, with the density estimated using the Span and Wagner EOS implemented in the NIST Webbook (https://trc.nist.gov/TDE/Help/TDE103b/ProgramMenus/EOS-Menu.htm). There is good comparison between the two EOS methods.

# 4.0 COMPUTATIONAL MODELING RESULTS

## 4.1 PREDICTIONS OF MODEL BEHAVIOR

The model primarily considers advective transport of sequestered carbon dioxide into each of two injection zones:

- Annona Injection Zone (Injection Zone #1) (if used; proposed to be held in reserve)
- Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone #2)

The Upper Tuscaloosa / Paluxy Injection Zone is the primary interval proposed for sequestration. To take advantage of its specific qualities, completions in the interval are expected to be controlled by "smart-well" technology, with each well completed separately (via packers, etc.) into both the:

- Upper Tuscaloosa (Upper Interval), and the
- Upper Tuscaloosa (Lower Interval) and Paluxy

This proposed completion strategy in the project injection wells is intended to maximize the volume of supercritical carbon dioxide that can be sequestered. Each of the interval layers has been modeled separately since each completion in the injection wells is specifically tailored to its interval layers and the model constrains the maximum injection into each such targeted layer.

Strategic Biofuels proposes to drill and complete three injection wells: LGF W-N1, LGF W-N2, and LGF W-S2. In map view, the locations of the three injection wells are aligned in the geospatial form of an inverted triangle (Figure 1). The model assumes each of the three injection wells fully penetrates the modeled interval, and all three wells inject simultaneously into each interval. In each completion, "skin" (near-wellbore formation damage) is assumed to be zero.

Modeled cumulative injection into the Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone #2) is 38.44 million metric tons over its 20-year injection life, or 1.922 million metric tons per year. Injection into the (currently reserved) Annona Injection Zone (Injection Zone #1) would be 3.94 million metric tons over its 20-year injection life. The injected volumes can be safely accomplished using injection pressures that are less than the 80% of calculated fracture pressure limit specified by CARB LCFS Protocol Subsection C.3.3(b). The CARB 80% LCFS Protocol limit is conservative and provides an additional margin of safety to the 40 CFR §146.82 standard, which is set at 90% of the fracture pressure. The maximum allowable downhole injection pressure at each well is specified and the model uses that pressure limit to constrain injection rate, if reached.

The model allows injection into the entire layer, at each well, and the sequestered carbon dioxide is distributed throughout the entire completion over the 20-year injection process. Carbon dioxide tends to move vertically due to buoyancy forces until it encounters the sequestration zone's upper confining or containment (*i.e.*, impermeable) topseal or "caprock" layer. The largest volume of carbon dioxide will be sequestered within the most porous and permeable layer in each interval.

## 4.2 MODEL CALIBRATION AND VALIDATION

In the final upscaling from the Static Models to the Dynamic Models, assigned interval permeability-thicknesses are calibrated to the injection/fall-off test – derived permeabilities in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841) (see Section 3.2). These upscaled permeability-thickness values were verified by simulating water injection in Reveal into the test intervals in the Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). The site model will be updated with additional site-specific data acquired during the drilling and completion of the project injection wells. These data and input parameters will be adjusted to reflect the acquired information from core analyses and open hole well logs. Once the injection of supercritical carbon dioxide has been initiated, the models will be periodically updated (at least every 5 years), and each updated model will integrate all of the pressure and rate data from each injection well and the direct / indirect monitoring of the advancing plume geometry over time.

The parameters used in this model are established from the compilation of site-specific data and the integration of regional data and relevant literature where there are gaps in the "local" data sets. The model reflects a "most-likely" scenario, based on the information and data currently available. Changes in the net thickness, composition and distribution of flow units, as well as changes in rock properties such as porosity, permeability, *in-situ* water density, and compressibility may yield changes in final pressure and plume growth rate and lateral extent at the end of the modeled 20-

year operational period, followed by a 100-year post-closure period.  Once the spatial variability of the key parameters has been determined following the drilling and completion of the project injection wells, a Sensitivity Analysis that incorporates the defined range in parameters will be performed to meet the requirements pursuant to 40 CFR §146.93(c)(2)(iv).

# 5.0 MODEL RESULTS

## 5.1 PREDICTED POSITION OF THE CARBON DIOXIDE PLUME

Analytical models from Celia and Nordbotten (2009) and Yamamotoa and Doughty (2011) suggest that within a vertically contiguous injection layer the plume is smallest at the base and extends asymptotically outward with the maximum plume extent at the upper boundary between the (porous) injection layer and the overlying confining / containment layer. This analytical approach can mathematically extrapolate the saturation profile to the near-molecular level but is limited by the requisite simplifying of assumptions regarding the spatial distribution of rock properties.

The numerical model determines pressure and saturation within each grid block, with each grid block having its own volume and potentially unique properties (permeability, porosity). All layers incorporate the spatial variability of the sand and shale facies, as well as porosity and permeability. In the numerical model, vertical permeability is assumed to be 10% of horizontal permeability.

Supercritical carbon dioxide saturation plume plots are presented in Appendix 12, at 5-year intervals, for the top layer in each injection layer. The top layer of each zone is chosen because it presents the maximum plume extent due to the density contrast between carbon dioxide and water.

- Figure 17 plots the aerial extent of the Annona Injection Zone (Injection Zone #1) Saturation Plume at the End of 20 Years
- Figure 18 plots the aerial extent of the Upper Tuscaloosa (Upper Interval) Injection Zone (Injection Zone #2, Upper) Saturation Plume at the End of 20 Years
- Figure 19 plots the aerial extent of the Upper Tuscaloosa (Lower Interval) / Paluxy Injection Zone (Injection Zone #2, Lower) Saturation Plume at the End of 20 Years

A plot image of the composite aerial extent of the plumes in all intervals (operational and post-operational) is presented in Figure 20. This figure illustrates overall plume growth during the injection and post-injection shut-in period by overlaying the aerial extent of the saturation plumes from each interval and comparing the growth of the plumes over selected time intervals. The aerial extent of the saturation plumes are displayed at 5-year increments throughout the injection period (20 years), then at 30-, 50-, and 100-years post-closure.

At the onset of injection, the saturation plume extends radially out from each injection well. It is eventually constrained by the pressure front created by a neighboring injection well, or resistance to flow due to formation depth and pressure and/or other reservoir properties. For example, the LGF W-S2 well plume is constrained in both north and south directions because it is bound by the advancing saturation plumes emanating from the LGF W-N1 and LGF W-N2 injection wells to its north, and by the higher formation pressure associated with deeper reservoir depths to the south. The LGF W-N1 and LGF W-N2 plumes are constrained in a southerly direction but are less constrained in the up dip (north) direction, and there is some interference between wells.

### 5.1.1 Maximum Plume Extent

Tables 31 and 32 show the maximum extent of the overall (aggregate) saturation plume at selected time periods. The distances are measured from the southernmost edge to the northernmost edge in all the injection layers and represent an outermost perimeter as presented in Figure 20.

**Table 31 Maximum Plume Extent – Northern Edge to Southern Edge**

| Injecting / Post-Closure | Year | Distance (miles) | Northern Drift Velocity (ft/year) | Southern Drift Velocity (ft/year) |
|---|---|---|---|---|
| Injecting | 5 | 3.677 | | |
| Injecting | 10 | 4.249 | | |
| Injecting | 15 | 4.711 | | |
| Post-Closure | 20 | 4.981 | | |
| Post-Closure | 50 | 5.602 | 115 | 5.6 |
| Post-Closure | 70 | 5.889 | 96 | 0 |
| Post-Closure | 120 | 6.541 | 84 | 0 |

**Table 32 Maximum Plume Extent - Western Edge to Eastern Edge**

| Injecting / Post-Closure | Year | Distance (miles) | Western Drift Velocity (ft/year) | Eastern Drift Velocity (ft/year) |
|---|---|---|---|---|
| Injecting | 5 | 4.261 | | |
| Injecting | 10 | 4.751 | | |
| Injecting | 15 | 5.163 | | |
| Post-Closure | 20 | 5.402 | | |
| Post-Closure | 50 | 6.153 | 59 | 73 |
| Post-Closure | 70 | 6.468 | 47 | 65 |
| Post-Closure | 120 | 6.787 | 25 | 48 |

During the active injection period, plume growth is primarily driven by the injection process. At the end of the injection period the plume has expanded ~5 miles from its southernmost edge to its northernmost edge. However, plume growth reaches maximum extent at the end of the 100-year PISC time frame with slow and decelerating movement due to the density contrast between the injected supercritical carbon dioxide and the *in-situ* formation brines.

### 5.1.2 Plume Movement Post-Closure

Density contrast between the sequestered supercritical carbon dioxide and the *in-situ* formation brine, along with the angle of formation dip, exerts a primary influence on the pressure differential that drives plume movement post closure. In general, a larger density difference between the *in-situ* fluid and the injected supercritical carbon dioxide increases the buoyancy velocity and therefore the plume size. Mobility (k/u) also impacts the rate of plume movement with time.

The following analytical relationship, without dispersion, is used to determine the initial drift velocity due to density differences between the injected fluid and formation fluid (note assumes isothermal conditions):

$$D_d = 9.49E^{-2}\left(\frac{(\rho_e - \rho_f)k\beta}{(\varphi\mu)}\right)$$

Where:

$D_d$ = density drift (ft/yr.)
$\rho_f$ = density of the native formation fluid ($gm/cm^3$)
$\rho_e$ = density of the effluent ($gm/cm^3$)
$k$ = permeability (darcies)
$\beta$ = formation dip rate (ft/mile)
$\varphi$ = formation porosity (fractional)
$\mu$ = fluid viscosity (centipoise)

The angle of structural dip is not uniform in all compass directions; accordingly, the rate of post closure plume movement is not equal in all directions. Additionally, the aerial extent of the injected supercritical carbon dioxide continues to very slowly expand (at a decelerating rate) long after injection ceases as injection-caused elevated reservoir pressure within the Area of Review dissipates (see Section 5.2.2 below); however, the plume extent does not increase significantly beyond the PISC timeframe. The maximum drift velocity occurs to the north (up dip), and to a lesser degree to the east and west of the injection wells. There is essentially no movement of the plume to the south due to increasing hydrostatic pressure in the downdip southerly direction.

It is expected that the inclusion of the mechanisms of capillary trapping and imbibition and the incorporation of additional site-specific data will demonstrate the likelihood of smaller plume radii. These features will be included in future modeling that will take into account the information provided by the additional geologic data obtained with the drilling, coring, logging, and testing of the planned injection wells.

## 5.2 PREDICTED PRESSURE INCREASE

Appendix 13 presents the estimated pressure contours in the top layer of each model, starting with the initial pressure and then incrementally expanding outward over time.

- Appendix 13.1 – Annona Injection Zone (Injection Zone #1)
- Appendix 13.2 – Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone #2)

Because all formations are dipping generally to the south in a monoclinal fashion, the initial pressure is lowest in the northernmost portions of the grid and greatest in the southernmost portions of the grid, just east of center. Once injection is initiated, the absolute pressure contours extend up dip (generally north) towards the shallowest part of each reservoir. The pressure is the highest at the point of injection and tapers off with distance away from each injection well.

The figures in Appendix 13 show the predicted position of the outward-advancing pressure contours at 5 years, 10 years, 15 years, and 20 years after the start of injection, with the 20-year contour representing the planned cessation of injection. Figures 22 to 24 present the pressure distribution in the top layer of each zone at the end of 20 years of injection.

- Figure 22 plots the aerial extent of the Annona Injection Zone (Injection Zone #1) Formation Pressure distribution (position) at the End of 20 Years
- Figure 23 plots the aerial extent of the Upper Tuscaloosa (Upper Interval) Injection Zone (Injection Zone #2) Formation Pressure distribution at the End of 20 Years
- Figure 24 plots the aerial extent of the Upper Tuscaloosa (Lower Interval) / Paluxy Injection Zone (Injection Zone #2) Pressure distribution at the End of 20 Years

The position of the maximum pressure front is presented in Section 6.2.

Plots of incremental pressure buildup over initial conditions are presented in Appendix 14. The predicted pressure profiles will be compared to observed plume and pressure data in the field from both injection wells and monitor wells and will be used to fulfil the EPA requirement to reevaluate the Area of Review at 5-year intervals during injection operations and during pressure recovery over the 100-year PISC timeframe.

### 5.2.2 Pressure Stabilization Post Shut-in

At the cessation of injection operations, pressure within the injected intervals dissipates but never completely returns to the initial pre-injection reservoir pressure. This behavior is not the result of a pressure increase due to the increased mass injected into the grid, nor a grid effect. The net pressure at the edge of the grid would be elevated, or reduced, relative to the initial pressure if material balance influenced the behavior, which is not the case. Incremental pressure contours above starting pressures shows the net pressure at the grid edge is zero in all cases (Appendix 14).

Instead, the pressures observed in the vicinity of the well is a result of the supercritical $CO_2$ having displaced formation brine in the pore space surrounding the injection well. Pressure equilibrium is maintained within the overall grid as evidenced by the same initial and final pressure at the shallowest and deepest part of the grid. The displacement and redistribution of the denser brine within the pore structure, replaced by the less dense supercritical carbon dioxide, results in the development of a different pressure distribution in the sequestered reservoir(s) near the injection wells to accommodate the same hydrostatic potential between the shallowest and deepest parts of the grid. Pressure distribution is also a function of structure (if any of consequence) near the well.

## 5.3 UNCERTAINTY IN THE MODELS

Model predictions such as plume aerial extent and pressure build-up within the targeted injection reservoir are dependent on (1) static properties (for example, structural dip, net thickness, porosity, permeability, kv/kh, lateral extent and continuity of inter-reservoir shale baffles, local and regional connectivity of the sandstone reservoirs, and/or connected aquifer volume), (2) dynamic properties (for example, relative permeability, capillary pressure, and system compressibility) and (3) formation conditions (pressure, temperature, brine salinity, mineralogy). In addition, operating parameters (for example, the rate of carbon dioxide injection and the total volume of carbon dioxide injected over time) will impact the pressure build-up at / around the well and in the surrounding reservoir.

The plume expansion and pressure build-up forecasts discussed in this permit application are derived from a “base” or “reference” case model which reflects a “most likely” estimate of static and dynamic properties and formation conditions based on the data currently available to estimate these properties.

Forecast uncertainty for the Louisiana Green Fuels site will be reduced through future data acquisition and analysis of site-specific parameters gathered during the drilling, coring, logging and testing of the proposed injection wells and the recompletion of the proposed monitor wells. Further reductions in uncertainty will be afforded with the ongoing operation and monitoring of the carbon sequestration project.

# 6.0 AREA OF REVIEW

Under the 40 CFR §146.84 regulations, the Area of Review is the area within which the owner or operator of a Class VI injection well must identify all artificial penetrations (APs; in this instance, legacy oil and gas test wells) that penetrated the Upper Confining Zone and/or injection zones and determine whether those APs have been completed or plugged in such a manner so that they do not provide vertical leak conduits for injectate / fluid movement. If inadequately constructed or abandoned, APs could be a possible threat to human health or the environment because of their potential for conveying injectate material, drilling fluids, or reservoir brine out of the injection zone or the legacy wellbore and upward into a USDW.

An Area of Review delineation for a 20-year injection forecast has been determined for the Louisiana Green Fuels, Port of Columbia Facility using site characterization data. Computational modeling was used to plot the projected lateral movement (expansion) of the sequestered carbon dioxide within each permeable layer during the operational and post-operational periods. Computational modeling has also been used to plot the location of the projected critical pressure front and the pressure recovery following cessation of sequestration activities post closure.

## 6.1 CRITICAL PRESSURE CALCULATIONS

When supercritical carbon dioxide is injected into a subsurface geologic formation, the pressure will increase. This pressure increase will be greatest at the injection well(s) and will steadily decrease with increasing distance from the injection site. Because of the driving force supplied by the increase in formation pressure within the injection zone, APs within the radius of the sequestered plume have the potential to convey carbon dioxide vertically out of the injection zone. Additionally, APs located outside of the sequestered supercritical carbon dioxide plume but within the pressure front have the potential to convey formation brines vertically out of the injection zone and into a USDW.

In an abandoned well, the driving force caused by sequestration injection is blocked by the flow resistance of the material (typically dehydrated drilling mud and/or one or more cement plugs) that occupy the borehole volume or, if cased, the casing annulus. In order to pose a potential threat to a USDW (*i.e.*, create a buildup in pressure from injection sufficient to drive fluids vertically upward into a USDW), the pressure increase in the injection zone must be greater than the pressure required to displace the material occupying the borehole volume or, if cased, the casing annulus. This pressure required to displace the material occupying the borehole volume is defined as the "allowable buildup pressure", and the perimeter of the area around the injection wells that is subjected to the allowable buildup pressure is known as the "pressure front".

### 6.1.1 Background

A column of drilling mud exerts hydrostatic pressure on the wellbore as the well is being drilled (active circulating conditions) and under static conditions once the circulation of the drilling mud ceases. The density of the drilling mud is formulated to yield a hydrostatic pressure in excess of the reservoir pressures encountered during the course of the drilling operation, preventing reservoir fluids from entering the wellbore. For a well to provide a vertical pathway to allow fluid movement, increased formation pressures (pressure due to sequestration plus original formation pressure) acting on the hydrostatic pressure of a static mud column abandoned in the wellbore must be greater than the mud column pressure (Davis, 1986). Exploration and production wells are commonly drilled "overbalanced", using a mud weight (density) that exerts a wellbore pressure that is typically 200 psi or more than the anticipated formation pore pressures expected to be encountered during the drilling activity (Pearce, 1989). When an oil or gas test well is abandoned as a dry hole, the dense drilling mud is left in place under overbalanced pressure conditions. Subsequently, one or more cement plugs are also set, including a cement plug set near the base of the USDW. In addition, the gel strength of the drilling mud in clay-based systems must also be taken into account. Gel strength refers to the shear stress required to initiate flow after long static periods of time (as is typical of the APs in this application, all for many decades) and is a measure of the degree of gelation that occurs due to the attractive forces between clay particles in the mud over time. The gel strength of a drilling mud adds to the flow resistance in the well and upward fluid movement cannot commence until the pressure in the injection zone has increased beyond a critical threshold value necessary to overcome the total flow resistance of the material occupying the borehole volume (*i.e.*, hydrostatic pressure of the mud column plus an additional force sufficient to overcome considerable gel strength).

As long as the pressure buildup in the injection zone at an AP is less than the calculated critical threshold value, that AP will not become a vertical conduit for fluid movement (Davis, 1986; Collins, 1986). Therefore, as long as the critical threshold value is not exceeded, the AP is not subject to fluid movement, remains as an effective barrier to upward fluid / injectate movement, and corrective action to re-enter and re-plug the subject legacy well is unwarranted and unnecessary.

#### *6.1.1.1 Properties of Clay-based Drilling Mud*

The physical characteristics which make drilling muds useful during drilling also make them effective barriers against formation fluid entry into a wellbore and preventing displacement of the mud column. This is particularly true of a commonly used base for mud, bentonite, which is predominantly a sodium montmorillonite clay. Bentonite-based mud types were used in legacy drilling operations in the area surrounding the Louisiana Green Fuels, Port of Columbia Facility. The platy electrically charged clay particles comprising bentonite strongly attract water, a polar molecule. This causes the clay to swell, thereby increasing the borehole fluid viscosity (Davis, 1986). Of the clays, montmorillonite has the greatest hydration potential and effects the greatest viscosity enhancement for a given amount of solids. This accounts for its long-standing popularity of bentonite as an additive to drilling muds.

An abandoned static mud-filled borehole (using conventional mud systems) contains a colloidal suspension of microscopic sized clay, barite, and other particles in water, which has set up to form a gel. The clay particles in this structure are immobilized mechanically by electrostatic forces. Specifically, the positively charged edges of the clay platelets align with the negatively charged flat surfaces of the adjacent platelets. It is the electrostatic attraction of the clay particles that gives the mud its gel strength and also prevents the clay and other particles from settling out in the mud. The ability of drilling mud to carry particles in suspension, even when static over long periods of time, is a key property of such drilling fluid. Without sufficient gel strength, the drilling mud would not be able to effectively remove excess solids during drilling operations and those solids would drop to the bottom of the borehole. Since the density of drilling mud is primarily a function of the suspended particles, the electrostatic immobilization of these particles prevents any potential loss in mud column density and hydrostatic pressure over time.

Water is a component of both drilling mud and formation fluids. Since water is a polar molecule, it will interact electrostatically with clay particles in the mud by hydrogen bonding. This will tend to immobilize water molecules within the gel structure of the mud and also prevent them from leaving the mud column. However, even if water molecules could diffuse out of a mud, each "lost" molecule of water would be replaced by a readily available counter-diffusing molecule from the surrounding formation fluids. The overall result would be no net gain or loss of water molecules into or out of the mud in the wellbore. Therefore, any diffusional interaction of water molecules between the formation fluid and the drilling mud would, at worst, result in no net density change for the mud, and density contrasts sufficient to create a driving force in the borehole will not occur.

The second important property – the gel strength of clay-based drilling muds – comes from the tendency of the plate-like clay particles to align so that positively-charged edges are adjacent to negatively charged flat surfaces. The gel is "a disheveled yet interconnected network of parallel clay particles separated by an average distance" (Jahnke, 1987). When the mud is agitated, the gel breaks down. If, on the other hand, the mud becomes static (uncirculated), then gel strength increases with time, as the additional clay particles come into alignment. This is documented by studies conducted by both Garrison (1939) and Gray, et al. (1980). If the drilling mud remains at rest (static) for a long time, high pump pressures are sometimes necessary to restore circulation in the borehole and, after long periods of time, are not always successful, requiring the mud to be drilled out of the wellbore. This strong resistive force in a mud column would also have to be overcome to permit vertical movement of the drilling mud, reservoir brines, or carbon dioxide to the base of the lowermost USDW.

Drilling mud is largely composed of clays and water. Commonly, bentonite-type clays (sodium montmorillonite) are added to the drilling mud to obtain viscosity in the slurry, in addition to promoting the formation of wall cake (the low-permeability layer of clay lining the borehole). Bentonite is hydrophilic (readily absorbs water), and its flat platy shape is the primary reason it is desired for use in drilling mud fluids. Because the platelets are electrically charged, clay platelets aggregate (flocculate) in three ways:

1) face-to-face,
2) edge-to-edge, or

3) edge-to-face

This thixotropic or gelling property of a bentonite slurry is what gives drilling mud its gel strength, as discussed above. Gel structures build with time as the positive edge of one particle or plate moves toward the negative surface of another; that is, when the platelets are layered (Gray et al., 1980). This orientation reduces the vertical permeability of the mud column significantly because vertical tortuosity is increased.

For many years, alternating cement and mud plugs have been advocated for properly abandoning well bores because they provide an effective barrier to vertical fluid movement. The "balanced method" is the most common method used for the placement of cement plugs during well abandonment procedures. Mud plugs have been shown to have a very low permeability and provide great resistance to fluid movement. In addition, mud plugs have been shown to plug an AP through time and under the various conditions encountered within a wellbore. A mud plug, with its inherent low permeability, in combination with the hydrostatic head of an overbalanced mud column under gelled conditions, is sufficient to counterbalance any increase in formation pressure due to sequestration effects, thereby creating an effective barrier to fluid flow. These sealing and fluid barrier characteristics of mud plugs, combined with hydrostatic pressures, cement plugs, and natural borehole closure processes, virtually eliminate the possible of developing a truly open conduit in an AP that was drilled through an injection layer.

The permeability of drilling mud in abandoned wells depends on the amount and size of the clay particles and other colloids available in the mud slurry, as well as the period of time the mud has been left static in the hole. Although the permeability of mud in deep boreholes has not been measured directly, the permeability of other similar clay mixtures, such as those used in slurry wall construction and bentonite grout slurry mixtures used to plug shallow borings has been quantitatively measured. Alther (1982), while investigating the use of bentonite for clay caps and slurry wall containment, found that a mixture of bentonite and high-permeability soils reduced the coefficient of permeability to $10^{-9}$ cm/sec using a falling head permeameter to measure the permeability of a mixture of 8 percent bentonite and 92 percent Lake Michigan sand. Geo-Solutions advertises permeabilities in the range of $10^{-6}$ cm/sec to $10^{-8}$ cm/sec for soil/bentonite slurry wall materials (https://www.geo-solutions.com/services/slurry-walls/soil-bentonite/), which is in agreement with *Engineering Bulletin – Slurry Walls* (EPA, 1992) and Ariyama et al. (1994).

Polk and Gray (1984) investigated the adequacy of mud as a sealing agent in abandoned boreholes related to mineral exploration. Their focus was on the ability of a bentonite mud to form a filter cake with a low enough permeability to ensure that there would not be fluid flow between aquifers penetrated during drilling. Polk and Gray (1984) directly measured filter cake permeabilities using the cake formed in a standard American Petroleum Institute (API) filter press filtration test run for 30 minutes at a differential pressure of 100 psi. The cake that formed on the filter paper was then tested with water to determine the cake's permeability. The cake had measured permeabilities ranging from $2 \times 10^{-8}$ to $8 \times 10^{-9}$ cm/sec, which are regarded as low enough permeability values to prevent fluid flow from one aquifer to another through an open borehole. The filter cake essentially keeps all the solid particles within the mud column. The formation of these low permeability filter cakes is one of the most desirable properties of clay-based mud systems. Experiments show the filter cake to have permeability below micro-darcy values (Kelessidis, et al, 2007; Elkatatny et al., 2012). This mud filter cake acts as a membrane "skin" or barrier that effectively seal off formations and prevent fluid loss from the mud column to the formation or loss of fluid from the formation when the well was drilled.

Because the EPA defines "low permeability" for soil as $1 \times 10^{-7}$ cm/sec, the minimum required permeability of the three feet of compacted clay beneath a landfill or surface impoundment, then it is reasonable to believe that the permeability of a column or mud plug ($1 \times 10^{-7}$ cm/sec or less) is more than sufficient to prevent movement of fluids between formations within an abandoned deeper portion of an unplugged (with cement) wellbore.

#### *6.1.1.2 Long-term Properties of Drilling Mud*

Most drilling mud fluids are thixotropic, as they nearly always utilize clay as their colloidal base. Thixotropy is the characteristic whereby certain gels evolve to a solid state when allowed to stand undisturbed but liquefy upon shock disturbance (Ochoa, 2006; Tehrani, 2008). In drilling mud fluids, thixotropy is caused by using clay minerals in the size range of colloidal particles (<0.00024 mm) as additives. Due to their very small size, they remain in suspension indefinitely (Davis, 1986). They enhance the formation of the gel phase of the mud. This gel phase is desirable because it assists in suspending cuttings released by the drilling procedure, producing the required viscosity and mud cake properties of the mud. The development of gel strength in a mud is due to the tendency of the clay platelets to align in a configuration where positively charged edges are adjacent to negatively charged surfaces. Collins (1986) and Collins and Kortum (1989) conducted laboratory experiments to test the predicted maximum allowable pressure necessary to displace static mud in laboratory equipment. They found that the displacement pressure exceeded the calculated values from the mud weight and the equivalent gel strength (determined at 12 hours) and concluded that the difference is a result of non-uniformities in borehole diameter. These non-uniformities increase the pressure necessary to break the strength of the gel in a borehole by a factor of two to five, to a value of ten-fold, over the gel strength alone (Collins, 1986; Collins and Kortum, 1989). This would add a significant margin of safety to abandoned well modeling calculations.

The functions of the drilling mud result from its physical properties. The primary functions of drilling mud are to prevent the influx of formation fluids and prevent the collapse of formation materials into the wellbore. These are primarily accomplished by altering the mud weight during drilling. Mud weight can be increased by increasing the salinity of the mud or by adding insoluble solids, typically barite ($BaSO_4$). In general, mud weight is increased with depth so that the mud column will continue to overbalance the encountered formation pressures by 200 to 400 psi (Pierce, 1989). The physical characteristics that make the mud useful during drilling also make it an effective barrier to vertical fluid movement over the long-term.

#### *6.1.1.2.1 Static Mud Column Height*

In general, the top of the mud column is found at, or very near, ground level for re-entered boreholes. Documentation offered from field examples are:

- The Nora Schulze wellbore, located in Nueces County, Texas, was reentered by K. E. Davis Associates during 1988. The top of the mud plug was encountered immediately below the cement plug at the top of the wellbore (top cement plug), with no fallback in the mud column.
- Subsurface, Inc. (1976) reentered and re-plugged the Brewster Bartle Drilling Company (British American Oil Production Company), University of Texas No. 1B well located in Galveston County, Texas, at the request of Amoco and Monsanto. During the re-entry

operation, drilling mud was found immediately below the surface cement plug with its properties relatively intact. This confirms that mud properties maintain their plugging capabilities and offer major resistance as fluid barriers.

- AIC (1988), in a study of well reentries originally plugged 20 to 30 years prior, found that in the Texas Gulf Coast, most operators reported that the original drilling mud encountered (left) in the re-entered well was generally hard, with the following comments reflecting the condition of the drilling mud and/or borehole fluids encountered in the Gulf Coast.

- Mr. John Luttig, P.E., stated in a letter that he has never encountered voids in a wellbore devoid of drilling mud in any well re-entry in more than 30 years in the oil fields of East Texas (Luttig, 1990: Pers.Com.). This includes wells that had been plugged for more than 50 years following plugging. He also indicated that he confirmed this statement with his contemporaries.

It is virtually impossible to force significant quantities of mud out of the borehole and out into a permeable formation because of the effect of nearly impermeable residual mud cake that forms along the formation wall of such permeable formations.

##### *6.1.1.2.2 Long-term Mud Column Properties*

The long-term properties of mud can be determined from a theoretical standpoint. Mud weight should not vary significantly from that at abandonment because virtually all the weighting (barite) particles will remain in suspension due to mud gel strength, which quickly develops. Pearce (1989) found that gravitational settling of barite or other mud additives has been overestimated. Even though some settling of the largest drill cuttings particles may occur, overall, this effect does not diminish mud density, or more importantly, affect the plugging and sealing characteristics of a column of mud in an abandoned borehole. The higher the gel strength of a mud column, the larger the particle that can remain in indefinite suspension. This is completely analogous to a solid mechanics problem where a sphere is suspended in an elastic solid. Only when the maximum shear stress on the surface of the particle exceeds the gel strength of the mud will the particle have the potential to settle out of the mud column. For mud-based barite weighting particles, with a density of 4.2 gm/cm$^3$, the critical diameter (in centimeters) for settling is approximately equal to the gel strength of the mud (lb./100 ft$^2$) divided by 100. For a reasonable low-end ultimate gel strength of 20 lb./100 ft$^2$ (typically required at 30 minutes measurement time in a mud) all barite particles smaller than 0.2 cm will remain in indefinite suspension. In a typical weighted drilling mud, barite particles are generally an order of magnitude less than 0.2 cm in diameter (NL Baroid, 1988). The maximum diameter of the largest 3 percent of the barite particles in standard API weighted mud systems can be no greater than 0.00635 cm (Gray et al., 1980), or 31 times smaller than the theoretical settling particle size. A gel strength of only 6 lb./100 $ft^2$ is needed to suspend 97 percent of the barite in the mud column and the larger drilled solids in the well (Pearce, 1989). Even if these larger drilled solids settle out of the mud, this will not readily affect the weight of the mud as these larger drilled particles are routinely screened out of the mud at surface anyways during the active drilling and circulation of the mud system at the shaker screens (Pearce, 1989).

Since the solids remain in suspension in the mud column, the only way to relieve formation stresses imposed on the static mud column is by compaction and the consequent movement of water from the mud out into the formation. However, this process is self-limiting, as any water movement from the mud column would increase the average density of the mud due to the loss of low-density water, increase the gel strength and bring suspended solids closer together, thus decreasing the effective permeability of the mud column (Pearce, 1989).

#### *6.1.1.2.3 Long-term Mud Column Gel Strength*

The relationship between gel strength and time varies with the mud type, depending on such variables as composition, pH, temperature, pressure, solids, and degree of flocculation (Figure 25). Srini-Vasan (1957) investigated the effect of temperature (up to 220 $^{o}$F) on water-based muds with drilling weights. Annis (1967) showed that the gelling process is dependent on both time and temperature, with 18 parts per billion (ppb) bentonite solution at any temperature having a gel strength equivalent to six times that of the initial gel strength of the mud. Vryzas et al. (2016) found that the gel-like structure of water/bentonite suspensions proved to be rheologically stable after an aging period of 30 to 60 days.

As shown in Davis and Pearce (1989), Chevron conducted laboratory experiments to determine the expected condition of mud left in wellbores. Chevron formulated muds like those used in Mississippi and “aged” the mud samples at temperature and pressure for a two-week period. The testing showed that the muds developed significant compressive strength and was described as a “plug”, with a gel strength too high to measure with standard equipment (Davis and Pearce, 1989).

Field evidence of the longevity of mud as a plugging material has been demonstrated during well reentries. The Nora Schulze No. 2, located in Nueces County, Texas, was re-entered by Envirocorp in the late 1980’s. The well was plugged and abandoned with 10.6 to 11.0 lb./gal mud when abandoned in 1959 (Pearce, 1989). Mud samples were taken upon reentry to a depth of approximately 754 feet using tubing pushed into the mud column starting from a depth of 120 feet. Below a depth of 754 feet, the mud could only be displaced from the well by breaking circulation (*i.e.*, the tubing string could not be advanced) (Pearce, 1989). Results of measured mud characteristics are presented in Figure 26. The average mud weight of the recovered samples was 11.1 lb./gal, showing that the mud did not appreciably change over the intervening 29 years following original abandonment. The gel strengths of the samples ranged between 217 lb./100 $ft^2$ to greater than 320 lb./100 $ft^2$. These values are over an order of magnitude greater than the 20 lb./100 $ft^2$ value commonly used for abandoned well assessment purposes (Pearce, 1989). In addition, shear strengths of the mud samples ranged from 170 lb./100 $ft^2$ to 7,000 lb./100 $ft^2$, increasing with depth (Pearce, 1989).

Additional information on mud characteristics from well reentries are:

- Subsurface, Inc. (1976) re-entered and replugged the Brewster Bartle Drilling Company (British American Oil Production Company), University of Texas No. 1B well located in Galveston County, Texas, during 1976, at the request of Amoco and Monsanto. Cement plugs were placed from 11,000 to 11,200 feet, and from 130 to 180 feet, and near the surface (top cement plug) with mud-laden fluid filling the remainder of the wellbore (conforming to Texas Railroad Commission plugging and abandonment requirements). During the re-entry operation, drilling mud was found immediately below the surface cement plug with its properties relatively intact. The mud had to be circulated out using 12-lb/gal mud.

- AIC (1988), in a study of well reentries originally plugged 20 to 30 years prior, found that in the Texas Gulf Coast, most operators reported that the mud was generally hard, with the following comments reflecting the condition of the drilling mud and/or borehole fluids encountered in the Gulf Coast:

    - mud set up like cement;
    - mud set up firm after about five years; and
    - mud encountered is hard and firm

- In an expert opinion, Mr. A. Hadaway (personal communication, 2019), who has over 37 years of experience in drilling and completions, stated that based on his experience in reentering 20 wells over the course of his career stated that "the mud remaining in the wellbores was generally observed to be thick and semi-rigid (similar to thick toothpaste) and contained essentially the original mud qualities present when emplaced, but with a much higher mud weight, gel strength, and viscosity due to partial water loss."

#### *6.1.1.3 Borehole Stability*

Along the Gulf Coast, borehole conditions are likely to have degraded significantly over time. This section discusses the mechanisms for borehole degradation, collectively called borehole "self-healing", which significantly reduces the crossflow risk within APs. These mechanisms are:

- **Clay Swelling**: Smectite-rich clay is common in the region and can absorb water molecules resulting in the internal structure changes and significant clay volume increases to create a seal/hydraulic barrier along the legacy borehole.
- **Shale Creep**: Under stress conditions induced by drilling a borehole, highly ductile shale can deform plasticly toward lower stress (borehole) to close off the legacy borehole.
- **Borehole Collapse**: Unstable borehole conditions during drilling is common in the area due to unconsolidated sand and ductile shale, especially in the shallow Tertiary-aged strata. Sand and shale from collapsed sections could fall in and fill up the borehole, providing capillary resistance to brine crossflow out of the injection zone via the legacy borehole.

These mechanisms can work in parallel and ultimately form a collective barrier to significantly reduce the risk of brine flow out of the injection zone via an AP. One of these mechanisms can be more effective than another, depending on rock properties, clay composition, mud composition left in borehole, the well abandonment schematic and practice. It is also well known that an attempt to access an open-hole section in legacy wells in south Louisiana has a very low chance of success due to borehole degradation.

##### *6.1.1.3.1 Clay Swelling*

Smectite-rich clays are known to represent a potential drilling hazard due to problems with clay swelling, resulting in borehole instability identified by sloughing shale, tight hole, and bit balling. Smectite-rich clay can absorb water molecules by chemical osmosis when exposed to the typically low-salinity water in freshwater-based drilling mud. Clay absorbs water molecules into the clay platelet, resulting in an increase in clay volume (Alcazar-Vara and Cotes-Monroy, 2018). As shales are buried with depth, more water is squeezed out of the platy sheets by overburden pressures, and the force present is equal to the matrix stress. As the formation is drilled, compacting force is relieved on the borehole face by the drill bit. Consequently, hydration force equal to the degree of relief develops. For example, in a normally pressured (assume 9.0 lb./gal mud weight equivalent) shale at 10,000 ft deep, the shale hydration force in normal pore pressure is expected to be 5,320 psi, which is much greater than the 250-psi pressure differential as exerted on the face of the borehole wall (based on a drilling mud of 9.5 lb./gal at the same depth (10,000 feet)).

Davis (1986) summarized the ability of shales – especially smectites – to absorb water, causing instability resulting primarily from overburden pressure, pore pressure, and/or tectonic stress. The hydration of the clays causes the platy nature of the shale to become unstable and tend to flow in a plastic manner. Natural borehole closure mechanisms and shale "sloughing" can be directly attributable to adsorption of water by shale formations.

Closure is likely to be driven predominately by clay swelling when:

- The shale formation that was drilled is reported to have at least 80% smectite based on x-ray diffraction (XRD) testing.
- Gumbo or swelled clay was observed while displacing wellbore fluid to the mud of legacy well.

Clay swelling can take place within hours or days, while shale creep is a slow process which could take months to close off a borehole.

###### *6.1.1.3.1.1 Borehole Closure Test in Texas*

Clark et al. (2005) reports results from the DuPont Gulf Coast borehole closure demonstration, which was conducted across an 80-foot-thick clay/shale formation to address the Environmental Protection Agency's concerns about potential movement of injected fluids through legacy wells.

The test was conducted by underreaming the borehole to 11-inches and installing two pressure gauges through 2-7/8-inch tubing that straddled the target shale formation. Borehole fluid was displaced with mud, replicating the mud composition left in legacy wells. The well was then shut in for 7 days to monitor the pressure change over time. The pressure in both the upper and lower gauges were observed to decrease at the same rate initially. However, after three days, the pressure decrease in both gauges was no longer at the same rate. While the lower gauge equilibrated with formation pressure, the upper gauge pressure was still decreasing, indicating possible borehole closure to form hydraulic isolation between the two gauges.

An injection test was conducted after the well had been shut in for seven days. The open hole pressure was found to have increased to a maximum of 140 psi above hydrostatic pressure. The lower gauge recorded the active pressure increase in the test interval; however, the upper gauge did not record any pressure change. Thereby, demonstrating hydraulic isolation across the 80-foot clay/shale interval.

#### *6.1.1.3.2 Creep*

Shale creep has been recognized as barrier for well abandonment in the North Sea and the Gulf of Mexico (Vrålstada, et al., 2019). At the end of field life, wells require permanent plugging and abandonment (P&A) as part of decommissioning activities. Recent experience in Brent plugging activity (the UK North Sea) has proven shale creep can create a natural barrier by closing off a wellbore (Davison et al., 2017). Since the Brent plugging activity started in 2008, numerous cement bond logs have identified the creep behavior of the Horda and Lark formations forming a seal against the 9-5/8” casing and subsequent perforating and pressure testing of these annular barriers has shown good integrity such that they can be used in well plugging and abandonment (Figure 27). The Horda and Lark formations are smectite-rich shales which often cause significant drilling problems and borehole instability.

#### *6.1.1.3.3 Borehole Collapse*

Borehole collapse and/or rugosity is observed from open hole well log caliper data run in many of the shallow Caldwell Parish APs. The caliper data exhibits significant borehole enlargement (typically, washouts) across shale sections in the Paleocene and Eocene formations. As such caliper logs measure hole conditions immediately after the drilling of the well, it is plausible that such degradation can continue in an open hole section over a long period of time.

Shear failure analysis indicates significant rock failure around the circumference of the borehole across very shallow sand sections due to the low rock strength of the shallow unconsolidated sand (“hoop stress”). Although shear failure of the adjacent clays could be limited (based on the analysis), the analysis does not account for the clay-sand interaction that could further degrade borehole conditions.

If a borehole is left open for a long period of time, conceptually, borehole collapse could continue until post-failure stabilization is achieved. Thin-bedded shales could collapse if adjacent sands are dislodged due to lack of support. The dislodged sand and shale may fall into the borehole or form a pile of rubble around the failure zone. The pile of rubble could provide support and stop further borehole failure, thus eventually reaching post-failure stabilization of the wellbore.

## 6.2 AREA OF REVIEW DELINEATION

Under Federal 40 CFR §146.84 regulations, the Area of Review is the region surrounding a geologic sequestration project where USDWs may be endangered by the injection activity. The rules stipulate that the Area of Review be delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected supercritical carbon dioxide stream and is based on available site characterization, monitoring, and operational data. The pressure front is the zone (area) of elevated pressure that is created by the injection of carbon dioxide into the subsurface sequestration complex. For sequestration projects, the pressure front of an expanding carbon dioxide plume refers to the zone where there is a pressure differential sufficient to potentially cause the movement of injected fluids or formation fluids into a USDW.

The methodology used in this application for calculating the pressure front was originally developed by E. I. du Pont de Nemours & Co. (DuPont) for Class I hazardous injection wells. The methodology is also generally consistent with previous methods employed under the Underground Injection Control (UIC) program (Barker, 1981; Clark et al., 1987; Collins, 1986; Davis, 1986; Johnson and Greene, 1979; Johnson and Knape, 1986; Warner, 1988; Warner and Syed, 1986).

The basic underlying assumption in this approach is that in the absence of naturally occurring, vertically transmissive conduits (faults and fractures) between the injection zone and any USDW (such as at the Port of Columbia Facility), the only potential pathway between the injection zone and any USDW is through an artificial penetration (in this case, abandoned unsuccessful oil and gas test wells – dry holes). In order to pose a potential threat to a USDW (*i.e.*, create a pressure buildup from injection sufficient to drive fluids into a USDW), the pressure increase in the injection zone has to be greater than the allowable buildup pressure. Therefore, the pressure front is the area within which injection zone pressures are greater than the allowable buildup pressure.

As discussed earlier, a static mud column exerts pressure. For an abandoned well to provide a pathway for fluid movement, the pressures acting on the static mud column (pressure due to injection plus original formation pressure) must be greater than the static mud column pressure. In addition, in a static fluid column, the incremental resistance provided by the gel strength of the mud must also be considered.

In this case, for upward fluid movement to begin, original formation pressure ($P_f$) plus the pressure due to sequestration/injection ($P_i$) must be greater than the static fluid column pressure plus the gel strength of the mud. This relationship is based on a simple balance of forces (Davis, 1986):

$$P_f + P_i > P_s + P_g$$

Where:

$P_f$ = original formation pressure (psig)

$P_i$ = formation pressure increase due to injection (psi)

$P_s$ = static fluid column pressure (psig)

$P_g$ = gel strength pressure (psi)

Therefore, pressure increase due to injection must be greater than static fluid column pressure minus original formation pressure:

$P_i > P_s + P_g - P_f$

The initial step in calculating the allowable buildup pressure for defining the pressure front involves determining the maximum pressure buildup gradient. This gradient is derived by evaluating the range of mud weights reported during the drilling and plugging of the legacy wells surrounding the Port of Columbia Facility. Regulatory and well file data indicates the minimum mud weight utilized in all wells that penetrated the Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone #2) at time of abandonment was equal to or (in most instances) exceeded 9.9 lb./gal. The original formation pressure gradient within the Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone #2) was calculated by dividing the original formation pressure by the depth at which that pressure is taken. A good source of this important original formation pressure data is the recently-drilled and tested Louisiana Green Fuels #1 Stratigraphic Test Well (La SN975841). The numerous Upper Tuscaloosa / Paluxy reservoir pressure measurements acquired in this important test well, located in the approximate center of the Area of Review, were used to derive an original formation pressure gradient of 0.450 psi/ft (see **Module A**).

In iteration, the maximum pressure buildup gradient is calculated by subtracting the original formation pressure gradient from the 9.0-lb/gal-mud column gradient as is demonstrated by the following:

| | |
|---|---|
| 0.052 x 9.9 lb./gal = 0.5148 psi/ft | (mud column gradient, modified from Barker, 1981) |
| | 0.052 is a conversion factor and has units of gal/ft-in$^2$ |
| -0.450 | (original formation pressure gradient of the Upper Tuscaloosa / Paluxy Injection Zone) |
| 0.0648 psi/ft | (maximum pressure buildup gradient, based on 9.0-lb/gal mud) |

Thus, 0.0648 psi/ft is the allowable pressure buildup gradient allowed in the Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone #2) used to define the pressure front.

Computationally, the allowable pressure buildup is calculated at the top of each cell in the variable depth grid. This allowable pressure buildup is then compared to the sum of the initial formation pressure plus the incremental pressure due to injection (*i.e.*, the sequestration activity). Where this difference is negative, that cell block is located outside of the pressure front. Where the difference is positive, the cell is located inside of the pressure front. At the geographic locations where the values balance (*i.e.*, at an incremental difference of 0 psi), this defines the pressure front perimeter. The location of the pressure front is plotted at the end of 20 years of injection and a "composite" perimeter is defined from the outermost pressure front segment in each of the permeable units. The pressure front at the end of 20-year injection period is shown in Figure 28.

# 7.0 CORRECTIVE ACTION PLAN

Whenever an effluent is injected into a subsurface geologic formation, the pressure within the injection zone(s) will increase. This pressure increase will be greatest at the injection well(s) and will decrease with distance away from the injection site. Because of the driving force supplied by the increase in formation pressure within the injection zone, APs (legacy wells) within the radius of the carbon dioxide plume have the potential to convey carbon dioxide out of the injection zone, and potentially into a USDW. In a borehole, this driving force is opposed by the flow resistance of the material (swelled clay, creeped shale, borehole collapsed material, *in-situ* drilling mud, and cement) residing in the well. Vertical fluid movement out of the storage complex cannot begin until the pressure in the injection zone has increased beyond a critical threshold value necessary to overcome the flow resistance of the borehole material. If the pressure buildup in the injection zone is less than the threshold value, the artificial penetration cannot serve as a conduit for flow of formation brines. Therefore, if the carbon dioxide plume does not reach that artificial penetration or if the critical pressure for crossflow is not exceeded for a legacy wellbore within the Area of Review, that well is considered to not represent a potential leak point in its current condition (*i.e.*, is “safe”), and corrective action to re-plug the well is not necessary.

After sequestration operations are completed, the pressure buildup within the injection zone will decrease back to a value approaching the original formation pore pressure. This occurs rapidly at first, within a few years of cessation of injection. Upon pressure stabilization in the injection zone, the carbon dioxide plume will be in hydrostatic equilibrium with surrounding formation brines. Consequently, no driving force capable of conveying carbon dioxide or formation brines out of the injection zone will be present.

An Artificial Penetration Protocol was used to identify, locate, and evaluate APs within the delineated Area of Review, defined as the pressure front perimeter, which is much larger than the modeled aerial extents of the sequestered carbon dioxide plumes. A methodology for evaluating the abandonment of legacy wells (dry holes) within the pressure front and/or within the modeled aerial extents of the sequestered carbon dioxide plumes was developed to evaluate each well’s potential to act as a vertical “leak” conduit. Wells known to have been properly plugged across the injection zone(s) cannot provide pathways for the movement of fluids from the injection zone upward into a USDW. These wells do not require any additional detailed evaluation. Wells that have been plugged across the lowest USDW, or at some depth between the injection zone and the lowest USDW, cannot serve as pathways for injection-induced movement of fluids into a USDW. Wells not known to have been plugged in either manner were further evaluated to determine if they may endanger the USDW.

## 7.1 TABULATION OF WELLS WITHIN THE AREA OF REVIEW

A thorough record search has been conducted during preparation of this Class VI permit application for the Louisiana Green Fuels site. This search is conducted to locate and evaluate wells that lie within the designated Area of Review. From the records obtained for each identified well, a determination of penetration of the confining and injection zones is first made. Each well has an assigned American Petroleum Institute (API) number, which is a unique number assigned to every oil and gas well within the United States. Additionally, in Louisiana, each well (regardless of use classification) is also assigned a Serial Number (SN), which is also used for search, tabulation, and evaluation purposes. Both of these identifiers are used track obtained well records.

### 7.1.1 Data Bases and Search Protocol

A specific and consistent methodology was used to identify APs within the Area of Review surrounding the Louisiana Green Fuels site. Implementing the Artificial Penetration Protocol for the project begins with the diligent collection of all available well data for APs drilled within the Area of Review. This well data was gathered from various data sources, including online public sources such as Louisiana's Strategic Online Natural Resources Information System (SONRIS) and commercial well data services such as TGS and IHS.

Several data sources were utilized to locate pertinent information regarding the locations of each AP. The geological project base map (see **Module A**) was checked and verified against similar maps provided by commercial map services and the SONRIS GIS online map service. Databases were compiled between December 2020 – December 2022 using the online SONRIS records, IHS Energy, and Enverus Drilling Information data and scout cards.

If discrepancies were found to exist among the various data sources, the reported regulatory data filed with the LDNR was considered to be the most accurate, as it was prepared by each well's operator and submitted to LDNR at the time the well was drilled. Additionally, data from the earliest reported sources were high-graded over data (depths, casings, etc.) reported on later forms.

#### *7.1.1.1 Search Procedure*

The search protocol for the project utilized public and private sources of data to identify active and plugged APs in Caldwell Parish, Louisiana. To begin the search of non-freshwater APs in the area, a project base map was compiled and used to determine well locations and land survey grids, such as townships, ranges, and sections.

The LDNR's Office of Conservation, is the state regulatory authority and repository for records of all wells drilled in the state and is considered the most reliable source of well data in Louisiana. This agency can usually provide 95 to 100 percent of the data needed, along with the online resources and the available hardcopies in the central file room.

The Louisiana well serial number is the most important reference identifier for accessing the well record file through the LDNR Office of Conservation Well File Department. The well serial number system is very efficient in the state of Louisiana. The Department of Conservation implemented the system at the time of its inception, and it remains active today. When an operator acquires a permit to drill in Louisiana, the proposed well is assigned a permanent serial number. Subsequently, any completion, plug back, deepening, or plugging reports are filed under this serial number regardless of any changes in operator ownership or lease name.

The Office of Conservation maintains a comprehensive set of well records on the SONRIS system (https://www.sonris.com/). This database allows a researcher to perform a search by inputting the township, range, and section of interest to receive a complete printout of all serial numbers permitted in that particular area. In addition, the SONRIS database has an interactive Public GIS Map, that a user may use by creating a search box/polygon around an area of interest, to also investigate records and data available for an area or perform a well-by-well individual search (http://sonris-www.dnr.state.la.us/gis/agsweb/IE/JSViewer/index.html?TemplateID=181). These databases are available to confirm well depth, status (expired permit, producing, or plugged), and current operator from a "Well Details Summary" as well as access to State Forms and Well Logs through “Document Access”.

Occasionally, there are instances in which well records or well logs are not located on the SONRIS system. In such cases, it is necessary to check the appropriate district office, which for Caldwell Parish is the Monroe District Office, located at:

24 Accent Drive, Suite 104
Monroe, Louisiana 71202.

Although the district offices primarily retain only more current data, some older data are available. These well records are also filed by the well’s serial number. District office personnel are sometimes able to provide other potential sources for information not otherwise available.

As a check and verification of state data, the search protocol uses various outside sources, including but not limited to the following:

**Louisiana Geological Survey:** This agency contains a library of geological reports, which, in some cases, provide information pertaining to a well with missing data. There also may be information relevant to the completion and plugging methods utilized in specific areas and/or during time periods. The Geological Survey can also provide recommendations of little known or underutilized sources of information.

**Commercial Log Libraries:** When required data cannot be obtained from either the LDNR or the Louisiana Geological Survey, data can be acquired through a commercial geologic and well log library. These libraries maintain extensive electric log collections as well as scout ticket files. Scout tickets often prove very valuable since full operator name or alternative operator names are listed. These alternative operator names often allow researchers to re-enter the Office of Conservation’s filing system with previously unknown record leads. Note: commercial data is often considered to be proprietary and may be considered CBI for application submittal.

**Direct Operator Contact:** If researchers are unable to find the desired information within the filing system of the Office of Conservation, the Geological Survey Center, or a commercial log library, then soliciting direct operator contact can be another option to obtain data on key wells. From organization reports on file with the Office of Conservation, operator address, and telephone numbers are retrieved, and the operator can be contacted to try and obtain well file copies or research data on the well.

As is often the case, operators of wells with incomplete records are no longer viable business entities. If the address and telephone number indicated on the organization report are no longer valid, then a search may be conducted of the corporate files of the Louisiana Secretary of State. These files indicate the approximate date a corporation has been dissolved or purchased by another entity. These files also give the last known address of all directors and officers. With this information, the search firms can utilize telephone directories to obtain telephone numbers of individuals in various cities.

In instances where the previous operator cannot be contacted or located, it is possible to obtain the name of the drilling contractor, cementing company, or logging company. These persons and/or companies are sometimes the only contacts available and may be able to provide partial well data on a well.

**County Deed Records:** In some cases, available base maps may indicate a well was drilled in an area, but the map does not always indicate an operator or lease name. It may be necessary to determine the genealogy of the mineral ownership and various lessors on a specific tract of land. By examining deed records on file in the parish of interest, one is able to ascertain the names of various individuals and/or companies that once owned mineral or drilling rights to a tract of land. These names can be utilized when re-examining the records on file with the various aforementioned public and private information sources.

**Aerial Photography:** A review of historical and current aerial photographs can assist in determining the existence of wells in an area. Aerial photographs are on file with various public agencies and private firms. Although these photos do not indicate operator or lease name, they can be beneficial in establishing base map errors or in locating a well on the surface.

For the Area of Review, the well locations and completion data were acquired using SONRIS and commercial resources. Well log data for nearly all of the wells within the Area of Review were generally available through such resources; however, several well logs could not be located. A list of these missing logs was provided to Tiger-Turpin Petroleum, LLC, which has an office located adjacent to the LDNR's central offices in Baton Rouge, Louisiana and is an LDNR-approved records search consultant. Tiger-Turpin Petroleum subsequently located all of the missing well logs for the APs that had penetrated the Upper Confining Zone, the Midway Shale, within the Area of Review. Well logs for two shallow Wilcox penetrations, neither of which penetrated the Upper Confining Zone, were never located; because neither shallow well represented a potential leak conduit from the proposed Injection Zones, it was determined that the logs from those two shallow Wilcox wells – which have now been demonstrated to not be available from any known source, including the LDNR's files – did not have a material impact upon the evaluation of APs that could constitute leak conduits within the Area of Review.

### 7.1.2 Wells Penetrating the Confining Zone and the Injection Zone

Wells that penetrated the Upper Confining Zone and/or the two Injection Zone may have the potential for conveying fluid from the injection zone and endangering the overlying USDW. Available geophysical well logs and state forms data from wells within the pressure front were evaluated to determine which of the wells penetrated the Annona Injection Zone and/or the Upper Tuscaloosa / Paluxy Injection Zone. Wells that did not penetrate either of the Injection Zones do not provide potential avenues for fluid movement and need not be evaluated further.

The majority of the man-made penetrations in the area consists of wells drilled for the shallow Wilcox "coal seam" (lignite) natural gas play of northern Louisiana. This shallow gas play includes "multi-seam" completions where the aggregate thickness of several thin coal seams contributes in aggregate to form an economically sufficient gas-in-place target. A second lignite gas play focuses on single-zone completions in the thicker Russell (middle Wilcox) or Reynolds (lower Wilcox) lignites, both of which are located well above the Upper Confining Zone, the Midway Shale. These shallow Wilcox gas wells reached total depth either just above the Midway Shale or just into the very uppermost portion of the Midway Shale. The Midway Shale is approximately 600 feet thick in the Area of Review and the top of the Midway is approximately 900 feet above the top of the

Annona Injection Zone (which is reserved for future use if needed; the actual top of the primary injection zone to be utilized, the Upper Tuscaloosa, is another 700 feet further downhole). Therefore, none of these shallow Wilcox wells need any further evaluation since these wells did not penetrate the entirety of the Upper Confining Zone and never reached either of the Injection Zones, either.

Well records information for these wells are contained in Appendix 15. APs that did penetrate either the Annona Injection Zone (Injection Zone #1) and/or the Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone #2) in the Area of Review are listed in Appendix 16.

### 7.1.3 Evaluation of Wells Within the Carbon Dioxide Plume

For the wells penetrating either the Annona Injection Zone (Injection Zone #1) and/or the Upper Tuscaloosa / Paluxy Injection Zone (Injection Zone #2), these wells were further segregated into two groups: those wells that are likely to be located within the advancing supercritical carbon dioxide plume front and those wells that are unlikely to fall within the carbon dioxide plume front but fall within the greater area encompassed by the advancing pressure front (the Area of Review). Wells anticipated to be located within the advancing carbon dioxide plume were evaluated at a much higher level of priority than the wells located beyond the advancing plume front but within the pressure front. Wells anticipated to be located within the advancing carbon dioxide plume are:

- Artificial Penetration No. 2 – Bradford Brown Trust Shipp #1 (La SN137738)
- Artificial Penetration No. 3 – Bass Keahey #1 (La SN165305)
- Artificial Penetration No. 6 – Magnolia Petroleum Co. O.N. Reynolds #1 (La SN57466)
- Artificial Penetration No. 7 –Louisiana Green Fuels #1 (La SN975841)

#### *7.1.3.1 Well Specific Evaluations*

Wells within the sequestered carbon dioxide plume are discussed individually, below.

**Artificial Penetration No. 2 – Bradford Brown Trust Shipp 1 (La SN137738)** - The Bradford Brown Trust Shipp #1 (La SN137738) well was drilled to a total depth of 4,520 feet rig kelly bushing, penetrating the upper portion of the Tuscaloosa. The well has 8-5/8-inch surface casing set to 565 feet and is an open hole to total depth. The well has a 75-foot cement plug that extends across the open hole within the USDW aquifer section, a 100-foot cement plug in the lower portion of the surface casing, and 10-foot cement plug at the top of the surface casing. Open spaces between plugs are filled with 10.9 lb./gal mud. The well is located outside of the anticipated plume area in the Annona Injection Zone but is located within the areal extent of the modeled sequestered carbon dioxide plume in the Upper Tuscaloosa / Paluxy Injection Zone. Additionally, the well was drilled in a prime monitoring area up dip area to the north of the Port of Columbia Facility. Therefore, Strategic Biofuels will re-enter this well and recomplete it as a project monitoring well during the construction phase of the project. The well will be deepened to 7,000 feet in the Paluxy Formation. Once completed, this will provide a direct In-Zone monitoring point for the project. For monitoring configuration, the well may be recompleted with carbon steel casing and standard oilfield cements. If this is the case, the well will be re-entered after any monitoring equipment is removed from the well once sequestered carbon dioxide reaches the well. In that case, a section of the casing straddling the top of the Upper Tuscaloosa will be milled out to a diameter exceeding the recorded bit diameter on the open hole caliper log. An acid resistant cement disk will be placed in the milled-out section of the well and the well will either be reconfigured for indirect monitoring or abandoned.

**Artificial Penetration No. 3 – Bass Keahey #1 (La SN165305)** - The Bass Keahey #1 (La SN165305) well was drilled to a total depth of 11,388 feet rig kelly bushing, bottoming in the Hosston Formation. The well has 9-5/8-inch surface casing set to 3,045 feet and is an open hole to total depth. The well has a 100-foot cement plug that extends across the surface casing shoe and open hole within the Upper Confining Zone (the Midway Shale) and a 50-foot cement plug at the top of the surface casing, which is cut off 5 feet below ground. Open spaces between plugs are filled with 9.9 lb./gal mud. The well is located outside of the anticipated carbon dioxide plume area for the Annona Injection Zone and the Upper Tuscaloosa / Paluxy Injection Zone; however, the well is expected to be located within the aerial extent of the sequestered carbon dioxide plume in the Upper Tuscaloosa / Paluxy Injection Zone over the PISC time-frame. USDWs are protected from endangerment by the cement plug across the surface casing shoe in the Midway Confining Zone.

As the well is in a prime location up dip area to the north of the Port of Columbia Facility, Strategic Biofuels will re-enter this well and recomplete it as a project monitoring well during the construction phase of the project. The well will be drilled and reamed out to 7,000 feet in the Paluxy. Once completed, this will provide a direct in-zone monitoring point for the project. For monitoring, the well may be recompleted with carbon steel and standard oilfield cements. If this is the case, the well will be re-entered after any monitoring equipment is removed from the well if sequestered carbon dioxide reaches the well. In that case, a section of the casing straddling the top of the Upper Tuscaloosa will be milled out to a diameter exceeding the recorded bit diameter on the open hole caliper log. An acid resistant cement disk will be placed in the milled-out section of the well and the well will either be reconfigured for indirect monitoring or abandoned.

**Artificial Penetration No. 6 – Magnolia Petroleum Co. O.N. Reynolds #1 (La SN57466) -** The Magnolia Petroleum Co. O.N. Reynolds #1 (La SN57466) well was drilled to a total depth of 4,105 feet rig kelly bushing, penetrating the Selma Chalk and bottoming in argillaceous chalk just beneath the Annona Injection Zone. The well has 7-inch surface casing set to 307 feet and is an open hole to total depth. The well has a 75-foot cement plug that extends across the open hole just above the Wilcox, a 50-foot cement plug in the lower portion of the surface casing, and bull plug at the top of the surface casing. Open spaces between plugs are filled with 10.0 lb./gal mud.

The well is located inside of the plume area in the Upper Tuscaloosa / Paluxy Injection Zone but is not drilled to a sufficient depth to penetrate the interval and is not in pressure communication with the Upper Tuscaloosa / Paluxy Injection Zone, The well is deep enough to penetrate the Annona Injection Zone but is not anticipated to be within its plume area (if utilized). As the well was drilled through the Annona Injection Zone, and is located within the Annona Pressure front, pressure effects on the well are discussed in the next section.

**Artificial Penetration No. 7 – Louisiana Green Fuels #1 (La SN975841) –** The Louisiana Green Fuels #1 (La SN975841) Stratigraphic Test Well was drilled to a total depth of 6,200 feet rig kelly bushing into the upper Paluxy. The well has 10-3/4-inch surface casing set to 1,223 feet, below the lowermost USDW, sealing off the local freshwater aquifers. An intermediate casing consisting of 7-5/8-inch pipe is set into the Selma Chalk at a depth of

3,889 feet rig kelly bushing and 5-inch production casing was set to total depth in the well. The well currently contains a hanging string of 2-3/8-inch tubing to 5,757 feet with the wellbore currently filled with 8.4 lb./gal fresh water containing corrosion inhibitor.

Once completed, this will provide a direct In-Zone monitoring point for the project. As the well is completed with carbon steel and standard oilfield cements, the well will be re-entered after any monitoring equipment is removed from the well once sequestered carbon dioxide reaches the well. A section of the casing straddling the top of the Upper Tuscaloosa will be milled out to a diameter exceeding the recorded bit diameter on the open hole caliper log. An acid resistant cement disk will be placed in the milled-out section of the well and the well will either be reconfigured for indirect monitoring or abandoned.

Of these four wells, the Magnolia Petroleum Co. O.N. Reynolds 1 (SN57466) was not drilled deep enough to penetrate the Upper Tuscaloosa / Paluxy Injection Zone, therefore, this well presents no immediate problem to planned sequestration activities. The well would only be a potential concern when and if carbon dioxide sequestration is later initiated in the Annona Injection Zone. However, the sequestered carbon dioxide plume in the Annona Injection Zone is not expected to extend out to reach this well, even during the PISC period.

The remaining 3 wells within the carbon dioxide plume area of the Upper Tuscaloosa/ Paluxy Injection Zone will be re-entered and recompleted as project monitoring wells. This will obviate the need to perform corrective action on wells within the carbon dioxide plume area of the Upper Tuscaloosa/ Paluxy Injection Zone.

### 7.1.4 Evaluation of Wells Within the Pressure Front

For the wells penetrating either the Annona Injection Zone and/or the Upper Tuscaloosa / Paluxy Injection Zone and are anticipated to be located beyond the aerial extent of the carbon dioxide plume but within the associated pressure front, these wells are evaluated separately than those within the plume. Wells anticipated to be encountered by the advancing pressure front (but not the carbon dioxide plume) are screened at a lower level of protection than the wells located inside the aerial extent of the carbon dioxide plume. Wells anticipated to be located within the advancing pressure fronts for either the Annona Injection Zone and/or the Upper Tuscaloosa / Paluxy Injection Zone are:

- Artificial Penetration No. 1 – J.S. Neilson C.G. Simmons #1 (La SN40405)
- Artificial Penetration No. 4 – G. Leiderman Vasser-Leiderman-Howard #1 (La SN48382)
- Artificial Penetration No. 5 – Houston Oil & Mineral Corp. C.O. Howard #1 (La SN172767)
- Artificial Penetration No. 8 – Southern Carbon USA #1 (La SN34225)
- Artificial Penetration No. 9 – Ouachita Expl. Co. Alma F. Jones #1 (La SN137572)
- Artificial Penetration No. 10 – C. H. Murphy Meredith #1 (La SN38817)
- Artificial Penetration No. 11 – J. F. Magalie Kellogg Bros. Inc. #1 (La SN31012)
- Artificial Penetration No. 12 –D. Meyers/Storm Olin #1 (La SN125019)

#### *7.1.4.1 Evaluation Methodology for Non-Endangerment*

Wells located outside of the modeled carbon dioxide plume but within the pressure front are evaluated against standards for non-endangerment. Evaluation steps to exclude wells from further evaluation include:

1. the well was not drilled deep enough to penetrate the Upper Confining Zone. These wells are not in pressure communication with the sequestration activities;
2. the well penetrated the Upper Confining Zone but was not drilled deep enough to penetrate either the Annona Injection Zone or the Upper Tuscaloosa / Paluxy Injection Zone. These wells are not in pressure communication with the sequestration activities;
3. the well penetrated the Upper Confining Zone but was drilled in an area where either the sandstones of the Annona Injection Zone and/or the Upper Tuscaloosa / Paluxy Injection Zone are absent. These wells are not in pressure communication with the sequestration activities;
4. the well penetrated either the Annona Injection Zone or the Upper Tuscaloosa / Paluxy Injection Zone but there is a cement plug spanning the entirety of the borehole below

the lowermost USDW and above the Annona Injection Zone and/or the Upper Tuscaloosa / Paluxy Injection Zone;

5. the well penetrated either the Annona Injection Zone or the Upper Tuscaloosa / Paluxy Injection Zone but if cased, the annular space of the outermost casing string across the Annona Injection Zone and/or the Upper Tuscaloosa / Paluxy Injection Zone is cemented; or
6. the well penetrated either the Annona Injection Zone or the Upper Tuscaloosa / Paluxy Injection Zone but the outermost casing string below the USDW and across the Annona Injection Zone and/or the Tuscaloosa/Paluxy Injection Zone has been perforated and squeeze-cemented, effectively sealing off the annular space to potential vertical fluid movement.

A pressure screening model was applied to wells that did not demonstrate one or more of the above screening criteria. Wells were modeled by comparing the predicted pressure increase from the Reveal model with conservatively calculated allowable pressure buildup (static column pressure plus minimum gel strength), using well-specific information contained in the well detail tabulation in Appendix 16. In cases where information was not available, conservative assumptions are made in the model calculations based on nearby drilling practices. The assumptions are summarized below:

a) For purposes of calculating gel strength, in cases where the open-hole borehole diameter across the injection interval sands is unknown, the surface casing outer diameter is used as the “equivalent” bit size. This is conservative since the actual bit diameter **must** be less than the inner diameter of the surface casing string.

b) For purposes of calculating gel strength, in cases where un-cemented protection casing extends across the injection intervals (*i.e.*, top of cement is below the injection interval), the protection casing diameter across the injection interval is used as the “effective” hole radius. This is conservative since the actual borehole diameter minus the protection casing diameter is significantly less than the outer diameter of the protection casing string.

c) For purposes of calculating gel strength, a conservative gel strength of 20-lb/100 sq. ft. is used. This is conservative as studies indicate that with time, the gel strength of mud is very likely to be more than an order of magnitude higher (Pierce, 1989).

d) For purposes of calculating the static mud column pressure, in cases where the weight of the mud in contact with the injection intervals is not available, a conservative drilling mud weight of 9.9 lb./gal is used for the wells. This is conservative since the available drilling information from legacy wells within the Area of Review indicates the mud weight used to drill through the Hosston Formation was always greater than 10 lb./gal.

e) In order to add a margin of safety in calculating the static column pressure, the depth to the top of the Upper Tuscaloosa is used in the calculations. This is conservative, as the pore pressure plus incremental injection pressures that are used in the screening are greater in permeable/porous layers deeper in the Upper Tuscaloosa / Paluxy interval.

The calculations used in the pressure screening assessment are presented below.

A static fluid column exerts pressure. The pressures acting on the static fluid column (pressure due to injection plus original formation pressure) must be greater than the static fluid column pressure, before fluid movement will start. In this case, for upward fluid movement to begin, original formation pressure ($P_f$) plus the pressure due to injection ($P_i$) must be greater than the static fluid column pressure:

$$P_f + P_i > P_s$$

Where:

$P_f$ = original formation pressure (psig)

$P_i$ = formation pressure increase due to injection (psi)

$P_s$ = static fluid column pressure (psig)

In other words, pressure increase due to injection must be greater than static fluid column pressure minus original formation pressure:

$$P_i > P_s - P_f$$

Static fluid column pressure is calculated using the equation:

$$P_s = 0.052 \times h \times M$$

Where:

$P_s$ = pressure of static mud column (psi)

$h$ = depth to the injection reservoir from the 50-foot fallback (feet)

$M$ = fluid weight (lb./gal)

and 0.052 is the conversion factor so that $P_s$ is in psi.

In an artificial penetration filled with a column of drilling mud, the gel strength of the mud must also be considered. In this case, for upward fluid movement to begin, original formation pressure ($P_f$) plus the pressure due to injection ($P_i$) must be greater than the static fluid column pressure plus the gel strength of the mud. This relationship is based on a simple balance of forces (Davis, 1986):

$$P_f + P_i > P_s + P_g$$

Where:

$P_f$ = original formation pressure (psig)

$P_i$ = formation pressure increase due to injection (psi)

$P_s$ = static fluid column pressure (psig)

$P_g$ = gel strength pressure (psi)

Therefore, pressure increase due to injection must be greater than static fluid column pressure minus original formation pressure:

$$P_i > P_s + P_g - P_f$$

For purposes of calculating the static mud column pressure, in cases where the weight of the mud in contact with the injection intervals is not available, a conservative drilling mud weight of 9.9 lb./gal was used for all wells. This is conservative since the available drilling information from area well logs indicate that the mud weight used to drill through the Injection Zones was always greater than 9.9 lb./gal, thus providing a margin of safety to these calculations.

The pressure due to gel strength (G) in an open borehole can be calculated from the following equation:

$$P_g = \frac{0.00333 \text{ x } G \text{ x } h}{d}$$

Where:

$P_g$ = pressure due to gel strength (psi)

G = gel strength (lb./100 $ft^2$)

d = borehole diameter (inches)

Where 0.00333 is the conversion factor, such that $P_g$ is in psi.

For a hypothetical open borehole, the added resistance due to gel strength for a mud with a very conservative ultimate gel strength of 20-lb/100 $ft^2$, in a 10-inch borehole, is approximately 6.7 psi for every 1,000 feet of depth.

For a cased hole, pressure due to gel strength (G) can be calculated from:

$$P_g = \frac{0.00333 \text{ x } G \text{ x } h}{d_b - d_c}$$

Where:

$P_g$ = pressure due to gel strength (psi)

G = gel strength (lb./100 $ft^2$)

$d_b$ = borehole diameter (inches)

$d_c$ = outside casing diameter (inches)

For a hypothetical cased borehole, the added resistance due to gel strength for a mud with a very conservative ultimate gel strength of 20-lb/100 $ft^2$, in a 10-inch borehole with 7-inch casing is approximately 22.4 psi for every 1,000 feet of depth.

As the above calculations show, gel strength provides a significant additional resistance to fluid movement due to injection. Additional conservatism is added to the present calculation by discounting borehole rugosity, which can increase the contribution in pressure from gel strength by a factor of 3 to 5 (Collins and Kortum, 1989) over that calculated for a "smooth" system. Using the above formulas for an open borehole and a cased borehole, the average measured gel strength from the Nora Schulze No. 2 well (267 lb./100 $ft^2$) (Pierce, 1989) and a factor of 3 contribution in gel strength due to borehole rugosity, the added resistance due to gel strength can reasonably be expected to be 266 psi per 1,000 feet of depth in an open borehole and 889 psi per 1,000 feet of depth in a cased well.

#### *7.1.4.2 Well Specific Evaluations*

Wells within the pressure front are discussed individually, below.

**Artificial Penetration No. #1 – J.S. Neilson C.G. Simmons #1 (La SN40405) –** The J.S. Neilson C.G. Simmons #1 (La SN40405) well was drilled to a total depth of 5,500 feet rig kelly bushing, penetrating the upper portion of the Paluxy. The well has 9-5/8-inch surface casing set to 565 feet and is an open hole to total depth. The well has a 60-foot cement plug that extends across the open hole at total depth, a 40-foot cement plug that extends across the open hole just above the top of the Tuscaloosa, and a 30-foot cement plug in the surface casing. Open spaces between plugs are filled with 10.3 lb./gal mud. The Upper Tuscaloosa / Paluxy Injection Zone is safe as the well has a cement plug in the confining interval just above the top of the Upper Tuscaloosa (in the Austin confining interval) that prevents fluid movement out of the Upper Tuscaloosa / Paluxy Injection Zone. Accordingly, the well will not come into contact with the carbon dioxide sequestered in the Upper Tuscaloosa / Paluxy Injection Zone.

The well is located outside of the calculated pressure front in the Annona Injection Zone and the well will not come into contact with the carbon dioxide sequestered in that Zone (if it is ever utilized). Therefore, this well is considered safe as currently abandoned.

No corrective action is warranted for this well for either the Upper Tuscaloosa / Paluxy Injection Zone or the Annona Injection Zone.

**Artificial Penetration No. 4 – G. Leiderman Vasser-Leiderman-Howard #1 (La SN48382)** – The G. Leiderman Vasser-Leiderman-Howard #1 (La SN48382) well was drilled to a total depth of 5,107 feet rig kelly bushing, penetrating the Lower Tuscaloosa Formation. The well has 10-3/4-inch surface casing set to 412 feet and is an open hole to total depth. The well has a 66-foot cement plug that extends across the open hole within the Wilcox, a 30-foot cement plug set just below the surface casing shoe, and a 5-sack cement plug at surface. Open spaces between plugs are filled with 10.6 lb./gal mud. The USDW is protected from endangerment by the open-hole cement plug set in the Wilcox formation.

In order to provide additional assurance of the safety of the well's current condition, the modeled incremental pressure increase at the well due to sequestration in the Tuscaloosa/Paluxy Injection Zone is calculated and compared to a static mud column and incremental gel strength (note any additional flow resistance from borehole rugosity and the cement plugs in the wellbore are not considered, which adds significantly to the safety of this screening calculation). This calculation is computed at the top of the Upper Tuscaloosa / Paluxy Injection Zone at the well (see Appendix 16) and shows that the incremental pressure increase in the Upper Tuscaloosa / Paluxy Injection Zone is always less than the allowable buildup pressure based on the static mud column and incremental gel strength; therefore, this well is considered safe as currently abandoned.

The well is located outside of the calculated pressure front in the Annona Injection Zone. Therefore, a pressure comparison is not needed for the Annona Injection Zone.

As the well will not come into contact with the sequestered carbon dioxide, no corrective action is warranted for this well.

**Artificial Penetration No. 5 – Houston Oil & Mineral Corp. C.O. Howard #1 (La SN172767) –** The Houston Oil & Mineral Corp. C.O. Howard #1 (La SN172767) well was drilled to a total depth of 16,308 feet rig kelly bushing, penetrating the Cotton Valley formation. The well has 13-3/8-inch surface casing set to 3,465 feet into the upper portion of the Selma Chalk. Protection casing (9-5/8-inch) is set to 13,790 feet, with 3,400 feet of it cut off and pulled from the well upon abandonment. A total of 1,420 sacks of Lite and Class "H" cement were used to set the production casing, which is insufficient to bring the top of cement much shallower than 8,500 feet. The remainder of the wellbore is an open hole to total depth. The well has a 161-foot cement plug near the bottom of the protection casing. A 165-foot cement plug is set across the surface casing shoe (and cut-off protection casing) at the base of the Midway Shale and the top of the Selma Chalk. This plug extends across the borehole and seals off the Annona Injection Zone and the Upper Tuscaloosa / Paluxy Injection Zone. A 15-foot cement plug is set in the top of the surface casing from its cut-off depth of 5 feet below grade. Open spaces between the protection casing (9-5/8-inch) and the borehole wall are filled with 10.6 lb./gal mud (mud weight at casing setting depth).

The Annona Injection Zone and the Upper Tuscaloosa / Paluxy Injection Zone are well isolated by the thick cement plug that straddles the base of the Midway Upper Confining Zone / top Selma Chalk interface.

No corrective action is warranted for this well.

**Artificial Penetration No. 6 – Magnolia Petroleum Co. O.N. Reynolds #1 (La SN57466) -** The Magnolia Petroleum Co. O.N. Reynolds #1 (La SN57466) well was drilled to a total depth of 4,105 feet rig kelly bushing, penetrating the Selma Chalk and bottoming in argillaceous chalk just beneath the Annona Injection Zone. The well has 7-inch surface casing set to 307 feet and is an open hole to total depth. The well has a 75-foot cement plug that extends across the open hole just above the Wilcox, a 50-foot cement plug in the lower portion of the surface casing, and bull plug at the top of the surface casing. Open spaces between plugs are filled with 10.0 lb./gal mud. The well is located outside of the anticipated plume area for the Annona Injection Zone but does penetrate the interval. The well was not drilled to a sufficient depth to penetrate the Upper Tuscaloosa / Paluxy Injection Zone, therefore, consideration of pressure effects on the well in the Upper Tuscaloosa / Paluxy Injection Zone need not be considered further.

The depth of the well was sufficient to penetrate the entirety of the Annona Injection Zone (see well log). The well is located outside of the anticipated plume area for the Annona Injection Zone, even over the PISC time period. The well is, however, contained within the area of the pressure front in the Annona Injection Zone. The USDW is protected from endangerment by the cement plug set above the top of the Wilcox, in the Cane River Shale.

In order to provide additional assurance of the safety of the well’s current condition, the modeled incremental pressure increase at the well due to sequestration in the Annona Injection Zone was calculated and compared to a static mud column and incremental gel strength (note any additional flow resistance from borehole rugosity and the cement plugs in the wellbore are not considered, which adds significantly to the safety of this screening calculation). This calculation was computed at the top of the Annona Injection Zone at the well (see Appendix 16) and shows that the incremental pressure increase in the Annona Injection Zone will remain less than the allowable buildup pressure based on the static mud column and incremental gel strength for the approximately 5.8 years of potential carbon dioxide injection into the Annona Injection Zone (currently held in reserve).

Although the well is nominally safe as currently abandoned, with a cement plug in the Wilcox, Strategic Biofuels will take a more conservative approach for a well that is located close to the injection well field. Prior to commencing carbon dioxide sequestration operations in the Annona Injection Zone, Strategic Biofuels will re-enter and plug the well placing an acid resistant cement at the top of the Annona Injection Zone, a second cement plug at the base of the Midway, and a cement plug within the Cane River Formation. Cement plugs will be set using the balance method and open spaces between the cement plugs will be filled with heavy mud.

**Artificial Penetration No. 8 – Southern Carbon USA #1 (La SN34225) –** The Southern Carbon USA #1 (La SN34225) well was drilled to a total depth of 6,006 feet rig kelly bushing, penetrating the upper portion of the Paluxy. The well has 10-3/4-inch surface casing set to 779 feet and is an open hole to total depth. The well has a 90-foot cement plug that extends across the open hole at the Cane River/Wilcox interface and protects the USDW from the deeper sequestration project. A 70-foot cement plug straddles the surface casing shoe, and a 10-foot cement plug is set at surface. Open spaces between plugs are filled with 10.6 lb./gal mud, the reported final drilling mud weight at total depth. The USDW is protected by the cement plug located at the top of the Wilcox and the well will not come into contact with the sequestered carbon dioxide.

In order to provide additional assurance of the safety of the well's current condition, the modeled incremental pressure increase at the well due to sequestration in the Annona Injection Zone is calculated and compared to a static mud column and incremental gel strength (note flow resistance from borehole rugosity and the cement plugs in the wellbore are not considered, which adds to the safety of this screening calculation). This calculation is computed at the top of the Annona Injection Zone at the well (see Appendix 16) and shows that the incremental pressure increase in the Annona Injection Zone will always remain less than the allowable buildup pressure based on the static mud column and incremental gel strength in the Annona Injection Zone. A similar comparison of the modeled incremental pressure increase at the well due to sequestration in the Upper Tuscaloosa / Paluxy Injection Zone is calculated and compared to a static mud column and incremental gel strength (note flow resistance from borehole rugosity and the cement plugs in the wellbore are not considered, which adds to the safety of this screening calculation).

This calculation is computed at the top of the Upper Tuscaloosa at the well (see Appendix 16) and shows that the incremental pressure increase in the Upper Tuscaloosa / Paluxy Injection Zone will always remain less than the allowable buildup pressure, based on the static mud column and incremental gel strength in the Upper Tuscaloosa / Paluxy Injection Zone.

Although no corrective action is warranted for this well, its location to the east of the sequestration complex affords the opportunity to use this well as a monitoring point. The Southern Carbon USA 1 (La SN34225) well will be re-entered and converted to a monitoring well as part of the Testing and Monitoring Plan (see **Module E**).

**Artificial Penetration No. 9 – Ouachita Expl. Co. Alma F. Jones #1 (La SN137572) –** The Ouachita Expl. Co. Alma F. Jones #1 (La SN137572) well was drilled to a total depth of 6,460 feet rig kelly bushing, penetrating the upper portion of the Paluxy. The well has 8-5/8-inch surface casing set to 601 feet and has 4-1/2-inch protection casing set to 3,085 feet into the Wilcox with 10.0 lb./gal mud recorded at total depth on the open hole log. The wellbore is an open hole to total depth. The USDW is protected by the cemented protection casing set in the Wilcox. The well was plugged under the LDNR’s Orphan Well program in August 2006. All of the plugs were placed above the protection casing setting depth. A cast iron bridge plug was set at 2,850 feet and a 200-foot cement plug was set on top of the bridge plug. A cement retainer was set at 1,140 feet and the well was perforated at 1,160 feet with 50 sacks of cement pumped into the perforations, placing cement against the Cane River and a 150-foot cement plug inside the 4-1/2-inch casing. The 8-5/8-inch by 4-1/2-inch casing annulus was cemented from 5 to 120 feet and an additional cement plug was placed inside the 4-1/2-inch casing from 5 to 150 feet. Open spaces between plugs in the 4-1/2-inch casing are filled with 9.0 lb./gal mud. The USDW is protected by the protection casing set and cemented in the Wilcox and the cement plug set inside and outside of the casing across the Cane River formation. The well will not come into contact with the sequestered carbon dioxide.

No corrective action is warranted for this well.

**Artificial Penetration No. 10 – C. H. Murphy Meredith #1 (La SN38817) –** The C. H. Murphy Meredith #1 (La SN38817) well was drilled to a total depth of 6,505 feet rig kelly bushing, penetrating the upper Paluxy. The well has 9-5/8-inch surface casing set to 838 feet and is an open hole to total depth. The well has a 50-foot cement plug that extends across the surface casing shoe and a 5-foot plug at surface. Open spaces between plugs are filled with 10.6 lb./gal mud. The safety of the well's current condition is assessed by comparing the modeled incremental pressure increase at the well due to sequestration in the Upper Tuscaloosa / Paluxy Injection Zone, which is calculated using a static mud column and incremental gel strength (note any additional flow resistance from borehole rugosity and the cement plugs in the wellbore are not considered, which adds significantly to the safety of this screening calculation). This calculation is computed at the top of the Upper Tuscaloosa at the well (see Appendix 16) and shows that the incremental pressure increase in the Upper Tuscaloosa / Paluxy Injection Zone is always less than the allowable buildup pressure for the first 17.5 years of sequestration operations. Therefore, this well is considered safe as currently abandoned until that time.

The safety of the well's current condition is assessed by comparing the modeled incremental pressure increase at the well due to sequestration in the Annona Injection Zone, which is calculated using a static mud column and incremental gel strength (note flow resistance from borehole rugosity and the cement plugs in the wellbore are not considered, which adds to the safety of this screening calculation). This calculation is computed at the top of the Annona Injection Zone at the well (see Appendix 16) and shows that the incremental pressure increase in the Annona Injection Zone is always less than the allowable buildup pressure during sequestration operations. Therefore, this well is considered safe as currently abandoned in the Annona Injection Zone.

The well is located just outside the sequestration plume fronts in the Annona Injection Zone and the Upper Tuscaloosa /Paluxy Injection Zone; therefore, the well is not expected to come into contact with the carbon dioxide sequestered in either zone.

Due to its optimal positioning, per the Testing and Monitoring Plan (**Module E**), Strategic Biofuels intends to re-enter this well and convert it to a monitoring well for the sequestration project. The well will thus serve as a key calibration point for the assessing the direct extent of sequestered carbon dioxide as well as monitoring pressure buildup in the Annona Injection Zone (if used) and the Upper Tuscaloosa / Paluxy Injection Zone. As the well will be completed for monitoring, no other corrective action is warranted.

**Artificial Penetration No. 11 – J. F. Magalie Kellogg Bros. Inc. #1 (La SN31012) –** The J. F. Magalie Kellogg Bros. Inc. #1 (La SN31012) well was drilled to a total depth of 6,343 feet rig kelly bushing, penetrating the upper Paluxy. The well has 9-5/8-inch surface casing set to 1,390 feet into the upper Wilcox and is an open hole to total depth. The surface casing seals off all of the USDWs from the deeper portions of the well. The well has a 50-

sack cement plug across the borehole at total depth, a 20-sack cement plug at the surface casing shoe that extends across the open hole, and a 5-sack cement plug in the top of the surface casing. Open spaces between plugs are filled with 9.9 lb./gal mud. The Upper Tuscaloosa / Paluxy Injection Zone is isolated as the well has a cement plug in the Wilcox and the well will not come into contact with the sequestered carbon dioxide. In order to provide additional assurance of the safety of the well's current condition, the modeled incremental pressure increase at the well due to sequestration in the Upper Tuscaloosa / Paluxy Injection Zone is calculated using a static mud column and incremental gel strength (note flow resistance from borehole rugosity and the cement plugs in the wellbore are not considered, which adds to the safety of this screening calculation). This calculation is computed at the top of the Upper Tuscaloosa at the well (see Appendix 16) and shows that the incremental pressure increase in the Upper Tuscaloosa / Paluxy Injection Zone is always less than the allowable buildup pressure; therefore, this well is safe as currently abandoned.

The well is located outside of the calculated pressure front in the Annona Injection Zone and the well will not come into contact with the sequestered carbon dioxide.

No corrective action is warranted for this well.

**Artificial Penetration No. 12 –D. Meyers / Storm Olin #1 (La SN125019) –** The D. Meyers / Storm Olin #1 (La SN125019) well was drilled to a total depth of 4,433 feet rig kelly bushing, penetrating the upper portion of the Selma Chalk but was not drilled deep enough to penetrate either the Annona Injection Zone or the Upper Tuscaloosa / Paluxy Injection Zone. The well has 8-5/8-inch surface casing set to 301 feet and is an open hole to total depth. The well has a 340-foot cement plug that extends across the open hole in the upper Wilcox, a 125-foot cement plug that extends across the surface casing shoe, and a 20-foot cement plug on top of the well. Open spaces between plugs are filled with 9.9 lb./gal mud. The USDW is protected by the 340-foot plug in the Wilcox that separates deeper strata from the shallower USDWs. The total drilled depth of the well is insufficient to penetrate the top of the Annona Sand Injection Zone, which is projected to be at a log depth of approximately 4,586 feet, if the well had been drilled deeper. There is approximately 153 feet of impermeable Selma Chalk between the well's total depth and the Annona Injection Zone. Additionally, the well is located outside of the calculated pressure front in the Annona Injection Zone and the well will not come into contact with the sequestered carbon dioxide. There is approximately 1,200 feet of impermeable Cretaceous Chalk between the well's total depth and the Upper Tuscaloosa / Paluxy Injection Zone. Therefore, this well is considered safe as the well is clearly not in pressure communication with either the Annona Injection Zone or the Upper Tuscaloosa / Paluxy Injection Zone.

No corrective action is warranted for this well.

Of the APs within the pressure front, only the Artificial Penetration No. 6 – Magnolia Petroleum Co. O.N. Reynolds #1 (La SN57466) might require corrective action during the modeled duration of the active sequestration project (and such corrective action needed only if the Annona Injection Zone is used for sequestration). As noted previously, prior to commencing carbon dioxide sequestration operations in the Annona Injection Zone, Strategic Biofuels will re-enter and plug the well in a more thorough manner as a precautionary measure.

## 7.2 CORRECTIVE ACTION SCHEDULE

Improperly constructed / plugged wells within the pressure front and/or those wells that are located within the sequestered carbon dioxide plume may require corrective action. Of the four wells that are anticipated to be located within the footprint of the sequestered carbon dioxide plumes, only the Magnolia Petroleum Co. O.N. Reynolds #1 (SN57466) well (Artificial Penetration No. 6) is potentially a concern. However, as this well is not deep enough to penetrate the Tuscaloosa/Paluxy Injection Zone, it only represents a concern regarding the shallower (reserved) Annona Injection Zone, which it did penetrate. This well will only require re-entry and re-plugging when, or if, carbon dioxide sequestration is initiated within the Annona Injection Zone. This well will be plugged prior to any active injection of carbon dioxide into the Annona Injection Interval.

Each of the remaining three wells located within the sequestered carbon dioxide plume for the Upper Tuscaloosa / Paluxy Injection Zone (Artificial Penetrations 2, 3, and 7) will be re-entered and converted to monitoring wells during the construction phase of the project. Therefore, these three wells will not require corrective action.

# 8.0 RE-EVALUATION SCHEDULE AND CRITERIA

## 8.1 AREA OF REVIEW RE-EVALUATION CYCLE

Strategic Biofuels will re-evaluate the Area of Review prior to the initiation of carbon sequestration (at the end of the injection well construction phase) and at least once every 5-years during the injection and post-injection phase per 40 CFR 146.84(e) of the project. Additionally, testing and monitoring of the site contains benchmarks / milestones that may trigger Area of Review re-evaluations on a more frequent basis (see **Module E**).

Testing and monitoring data will be collected continuously and reported quarterly. Injection operations will be monitored, and data will be reviewed and compared against the corresponding calculated output from the simulation model. These data will include (at a minimum):

1) Injection mass rates per day, volume rates, tubing head pressures and temperatures at each injection and monitoring well;
2) Downhole pressures and temperatures at each injection and monitoring well;
3) Where available, allocation estimates of carbon dioxide injection rates per zone;
4) Pressure fall-off transient test data; and
5) Above-zone pressure data from monitoring wells.

The Dynamic Model will be updated with the historical carbon dioxide injection volumes and pressures for each injection well and pressures for each monitoring well. The simulation model will then be history matched to observed conditions, which may include changes to the static model parameters. The Dynamic Model will then be projected forward and the areal distribution in pressures will be evaluated and its effect on APs will be reassessed. Additionally, any new APs within the pressure front (if extended) will also be evaluated at that time. If a larger Area of Review is delineated upon re-evaluation, the additional APs, if any, will be evaluated using the same methodology as employed in this application. New wells will be evaluated for status, construction and plugging details, location, depth of penetration, and verification that each new well meets the standard to prevent endangerment to USDWs and to prevent the movement of sequestered carbon dioxide out of the injection zone. Strategic Biofuels will assess and assign risk to determine if corrective action is needed.

## 8.2 TRIGGERS FOR UNSCHEDULED AREA OF REVIEW REEVALUATIONS

More frequent re-evaluation of the extent of the Area of Review may occur if unexpected conditions are detected in the monitoring framework. These changes may include unexpected fluctuations in pressure, temperature, water analysis, or major variations outside of the results predicted from the Reveal Dynamic Model. Examples of situations that may trigger an Area of Review re-evaluation are as follows:

1. Increases or decreases in downhole pressures that significantly depart from Dynamic Model simulation results;

2. Increases in formation pressures in the Above Confining Zone monitoring well, which could potentially indicate leakage of fluids above the sequestration complex;

3. An increase in the influx of carbon dioxide as measured in underground sources of drinking water or at the surface;

4. Exceedance of an operating parameter, as specified in the issued permit, such as any time that injection or formation pressures indicate or exceed fracture gradients;

5. New site characterization information that indicates that the Static Model needs revision; and

6. Arrival times of pressure pulses and or plume fronts that significantly vary from predicted direct or indirect monitoring.

Details of potential events that may trigger a reevaluation are contained in the M**odule E.** Strategic Biofuels will alert the UIC Program Director if a triggering event is experience and will provide a response strategy and timetable for implementation. Results of any investigation and results of any reassessment, and a schedule for performing any required remedial corrective action, will be presented to the UIC Program Director.

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